BEFORE THE ARIZONA CORPORATION COMMISSION

JIM O'CONNOR
CHAIRMAN
LEA MARQUEZ PETERSON
COMMISSIONER
ANNA TOVAR
COMMISSIONER
KEVIN THOMPSON
COMMISSIONER
NICK MYERS
COMMISSIONER

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS	DOCKET NO. E-01933A-22-0107

NOTICE OF FILING

The Residential Utility Consumer Office ("RUCO") hereby provides notice of filing its Redacted Direct Testimonies of Jeffrey M. Michlik and Crystal S. Brown and the Direct Testimonies of Bentley Erdwurm and John Cassidy in the above-referenced matter. RUCO is filing under seal, a copy of the Confidential Direct Testimonies of Jeffrey M. Michlik and Crystal S. Brown with the Hearing Division, the Legal Division and the Company.

RESPECTFULLY SUBMITTED this 11th day of January, 2023.

s/ Daniel W. Pozefsky
Daniel W. Pozefsky
Chief Counsel

ACC - Docket Control - Received 1/11/2023 12:02 PM
ACC - Docket Control - Docketed 1/11/2023 1:15 PM

ORIGINAL of the foregoing will be e-filed this 11th day of January, 2023 with:

https://efiling.azcc.gov
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

COPIES of the foregoing mailed/emailed this 11th day of January, 2023 to:

Michael Patten
Snell & Wilmer
400 East Van Buren
Phoenix, Arizona 85004
docket@swlaw.com
bcarroll@tep.com
jthomes@swlaw.com
mpatten@swlaw.com
Consented to Service by Email

Robin Mitchell
Legal Division
Arizona Corporation Commission
1200 W. Washington Street
Phoenix, Arizona 85007
legaldiv@azcc.gov
utildivservicebyemail@azcc.gov
Consented to Service by Email

Patrick Black
Fennemore Craig, PC
2394 East Camelback Road, Suite 600
Phoenix, Arizona 85016
Attorney for Freeport Minerals Corporation
khiggins@energystrat.com
pblack@fclaw.com
LFerrigni@fennemorelaw.com
PBlack@fennemorelaw.com
Consented to Service by Email

Daniel W. Pozefsky
RUCO
1110 West Washington Street, Suite 220
Phoenix, Arizona 85007
dpozefsky@azruco.gov
jmccarty@azruco.gov
procedural@azruco.gov
mhightower@azruco.gov
lwoodall@azruco.gov
rdelafuente@azruco.gov
Consented to Service by Email

Timothy M. Hogan
Arizona Center for Law in the Public Interest
352 East Camelback Road, Suite 200
Phoenix, Arizona 85012
Attorney for Vote Solar Southwest Energy Efficiency Project Wildfire; San Juan Citizens Alliance; Dine CARE; To Nizhoni Ani; and Black Mesa Trust
thogan@aclpi.org
Consented to Service by Email

Nicholas Enoch
Lubin & Enoch, P.C.
349 North Fourth Avenue
Phoenix, Arizona 85003
Attorney for IBEW Local 1116
nick@lubinandenoch.com
cristina@lubinandenoch.com
clara@lubinandenoch.com
morgan@lubinandenoch.com
Consented to Service by Email

Adam Stafford
Western Resource Advocates
1429 North 1st Street, Suite 100
Phoenix, Arizona 85004
adam.stafford@westernresources.org
Consented to Service by Email

Kurt J. Boehm
Boehm, Kurtz & Lowry
36 East Seventh Street, Suite 1510
Cincinnati, Ohio 45202
Attorney for The Kroger Co.
kboehm@bkllawfirm.com
jkylercohn@BKLlawfirm.com
Consented to Service by Email

Melissa M. Krueger
Pinnacle West Capital Corporation
400 North 5th Street, MS 8695
Phoenix, Arizona 85004
Attorney for Arizona Public Service Company
Melissa.Krueger@pinnaclewest.com
Theresa.Dwyer@pinnaclewest.com
Elizabeth.lawrence@aps.com
Jeffrey.Allmon@pinnaclewest.com
Ashley.Kelly@aps.com
Consented to Service by Email

James Corbin
617 North Loquat Avenue
Tucson, Arizona 85710
Jamescorbin13@msn.com
Consented to Service by Email

Vicki Baldwin
Parsons Behle & Latimer
201 South Main Street, Suite 1800
Salt Lake City, Utah 84111
Attorney for Walmart, Inc.
vbaldwin@parsonsbehle.com
Consented to Service by Email

Court Rich
Rose Law Group, PC
7144 East Stetson Drive, Suite 300
Scottsdale, Arizona 85251
Attorney for Arizona Solar Energy Industries Association Tesla, Inc. Sola Energy Industries Association NRG Energy, Inc.
hslaughter@roselawgroup.com
CRich@RoseLawGroup.com
ehill@roselawgroup.com
Consented to Service by Email

Chanele N. Reyes
Attorney
352 East Camelback Road, Suite 200
Phoenix, Arizona 85012
Attorney for Black Mesa Trust
chanele@aclpi.org
Consented to Service by Email

Louisa Eberle
Sierra Club Environmental Law Program
2101 Webster Street, Suite 1300
Oakland, California 94612
Louisa.eberle@sierraclub.org
Rose.monahan@sierraclub.org
Patrick.woolsey@sierraclub.org
Maddie.lipscomb@sierraclub.org
Consented to Service by Email

Karen S. White
2320 Dragon Fly Lane
Panama City, Florida 32450
Department of Defense and Federal Executive Agencies

Kyle Smith
The United States Department of Defense and all other Federal Executive Agencies
9275 Gunston Road, JALS-ELD
Fort Belvoir, Virginia 22060
Department of Defense and Federal Executive Agencies
Kyle.j.smith124.civ@army.mil
Consented to Service by Email

Robert J. Metli
Munger Chadwick & Denker, PLC
2999 North 44th Street, Suite 130
Phoenix, Arizona 85018
Attorney for CalPortland Company
rjmetli@mcdplc.com
wjerald@calportland.com
Consented to Service by Email

Autumn Johnson
AriSEIA and SEIA
7144 East Stetson Drive
Scottsdale, Arizona 85251
autumn@ariseia.org
Consented to Service by Email

By *s/ Renee de la Fuente*
Renee de la Fuente

TUCSON ELECTRIC POWER COMPANY

DOCKET NO. E-01933A-22-0107

REDACTED
DIRECT TESTIMONY
OF
JEFFREY M. MICHLIK

ON BEHALF OF THE
RESIDENTIAL UTILITY CONSUMER OFFICE

JANUARY 11, 2023

TABLE OF CONTENTS

Page

I. INTRODUCTION **1**

II. BACKGROUND **3**

III. SUMMARY OF FILING, RECOMMENDATIONS, AND ADJUSTMENTS **4**

IV. RATE BASE **9**

Fair Value Rate Base ("FVRB") 9
Rate Base Summary 9

V. OPERATING INCOME **10**

Operating Income Summary 10
Operating Income Adjustment No. 1 – Payroll Expense 10
Operating Income Adjustment No. 2 – Reverse Payment Card Processing Fees 12
Operating Income Adjustment No. 3 – Board of Directors Fees 15
Operating Income Adjustment No. 4 – TEP Short-Term Incentive Program or Performance Enhancement Program ("PEP") 17
Operating Income Adjustment No. 5 – Long-Term Incentive ("LTI") Compensation Program 24
Operating Income Adjustment No. 6 – Supplemental Executive Retirement Plan ("SERP") Expense 29
Operating Income Adjustment No. 7 – Severance Pay 35
Operating Income Adjustment No. 8 – Industry and Membership Dues 38
Operating Income Adjustment No. 9 – Other Membership Dues 43
Operating Income Adjustment No. 10 – Depreciation Expense 44
Operating Income Adjustment No. 11 – Rate Case Expense 44
Operating Income Adjustment No. 12 – Interest Synchronization 44
Operating Income Adjustment No. 13 – Income Tax Expense 45

ATTACHMENTS

TEP's Responses to Company Uniform Data Requests and RUCO Data Requests ..... Attachment A

SCHEDULES

Revenue Requirement ACC Jurisdictional RUCO-1
Gross Revenue Conversion Factor RUCO-2
Rate Base (OCRB, RCND and FVRB) – ACC Jurisdictional RUCO-3
Original Cost Raate Base – ACC Jurisdictional RUCO-4
Summary of Orignial Cost Rate Base Adjustments RUCO-5
Reconstruction Cost new Less Accumulated Depreciation – ACC Jurisdictional RUCO-6
Summary of Reconstruction Cost New Less Accumulated Depreciation Adjustments RUCO-7
Rate Base Adjustment No. 1 – Post-Test Year Plant, Routine Plant RUCO-8
Rate Base Adjustment No. 2 – Post-Test Year Plant Retirements RUCO-9
Rate Base Adjustment No. 3 – Accumulated Depreciation RUCO-10
Rate Base Adjustment No. 4 – Cash Working Capital RUCO-11
Rate Base Adjustment No. 5 – Regulatory Assets & Related ADIT RUCO-12
Summary – Operating Income Statement – ACC Jurisdictional – Adjusted RUCO-13
Test Year and RUCO Recommended Adjustments RUCO-14
Operating Income Adjustment No. 1 – Payroll Expense RUCO-15
Operating Income Adjustment No. 2 – Reverse Payment Card Processing Fees RUCO-16
Operating Income Adjustemnt No. 3 – Board of Directors Fees RUCO-17
Operating Income Adjustment No. 4 – Short-Term Incentive Program RUCO-18

Operating Income Adjustment No. 5 – Long-Term Incentive Program RUCO-19
Operating Income Adjustment No. 6 – Supplemental Exectuive Retirement Plan RUCO-20
Operating Income Adjustment No. 7 – Severance Pay RUCO-21
Operating Income Adjustment No. 8 – Industry Membership Dues RUCO-22
Operating Income Adjustment No. 9 – Other Membership Dues RUCO-23
Operating Income Adjustment No. 10 – Depreciation Expense.. RUCO-24
Operating Income Adjustment No. 11 – Rate Case Expense RUCO-25
Operating Income Adjustment No. 12 – Interest Synchronization.. RUCO-26
Operating Income Adjustment No. 13 – Income Tax Expense RUCO-27

EXECUTIVE SUMMARY

Tucson Electric Power Company ("TEP" or "Company") is classified as a class "A" utility. TEP is a for-profit, certificated Arizona public service corporation that provides electric utility service to various communities in Pima County, Arizona. On June 17, 2022, TEP filed an application with the Arizona Corporation Commission ("Commission") for a permanent rate increase. The TEP corporate business office is located at 88 East Broadway Blvd., Tucson, AZ 85702.

UNS Energy is a subsidiary of Fortis Inc., the largest investor-owned electric and gas distribution utility in Canada. UNS Energy is based in Tucson, Arizona and is the parent company of both TEP and UniSource Energy Services ("UES"). TEP serves more than 432,000 customers in and around Tucson, while UES provides natural gas and electric service to about 256,000 customers in northern and southern Arizona. Electric service is provided through a UES subsidiary called UNS Electric, Inc., while natural gas service is provided through a subsidiary called UNS Gas, Inc.

The Company utilized a test year ended December 31, 2021.

<u>Rate Application denoted in thousands of dollars:</u>

The Company-proposed rates, as filed, produce total operating revenue of $1.330 billion, an increase of $234.111 million or a 21.36 percent increase, over adjusted test year revenue of $1.096 billion. The Company-proposed revenue will provide operating income of $275.844 million and a 5.25 percent rate of return on its proposed $5.251 billion fair value rate base ("FVRB").

The Residential Utility Consumer Office ("RUCO") recommends rates that produce total operating revenue of $1.228 billion, an increase of $132.766 million or a 12.11 percent increase, over the RUCO-adjusted test year revenue of $1.096 billion. RUCO's recommended revenue will provide operating income of $236.068 million and a 4.65 percent return on the $5.072 billion RUCO-adjusted FVRB (see RUCO Schedule 1).

RUCO recommends that all its adjustments be adopted.

I. INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Jeffrey M. Michlik. I am a Public Utilities Manager employed by the Arizona Residential Utility Consumer Office ("RUCO"). My business address is 1110 West Washington Street, Suite 220, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as a Public Utilities Manager.

A. In my capacity as a Public Utilities Manager, I analyze and examine accounting, financial, statistical and other information and prepare reports based on my analyses that present RUCO's recommendations to the Arizona Corporation Commission ("Commission") on utility revenue requirements, rate design, and other matters. I also provide expert testimony on these same issues. In addition, I also supervise and review the work of other RUCO analysts.

Q. Please describe your educational background and professional experience.

A. In 2000, I graduated from Idaho State University, receiving a Bachelor of Business Administration Degree in Accounting and Finance, and I am a Certified Public Accountant with the Arizona State Board of accountancy. I have attended the National Association of Regulatory Utility Commissioners' ("NARUC") Utility Rate School, which presents for study and review general regulatory and business issues. I have also attended various other NARUC sponsored events.

I joined RUCO as a Public Utilities Analyst V in September of 2013. Prior to my employment with RUCO, I worked for the Arizona Corporation Commission in the Utilities Division as a Public Utilities Analyst for a little over seven years. Prior to employment with the Commission, I worked one year in public accounting as a Senior Auditor, and four years for the Arizona Office of the Auditor General as a Staff Auditor.

Q. What is the scope of your testimony in this case?

A. I am presenting RUCO's analysis and recommendations on Tucson Electric Power Company ("TEP" or "Company") proposed revenue requirement for TEP's application for a permanent rate increase. I am also presenting testimony and schedules addressing, operating revenues and expenses. RUCO witness Ms. Crystal Brown will be presenting RUCO's rate base adjustments. RUCO witness Mr. John Cassidy will be presenting RUCO's cost of capital analysis, and RUCO witness Mr. Bentley Erdwurm will be presenting RUCO's recommendations on rate design. In addition, Mr. Erdwurm will also be addressing the Company's proposed regulatory assets related to Demand Side Management ("DSM"), Electric Vehicle Infrastructure Investments, San Juan Materials. Mr. Erdwurm will also address the Renewable Energy Standard Tariff ("REST"), Environmental Compliance Adjustor ("ECA") and Resource Transition Mechanism ("RTM") which replaces the ECA. Finally, Mr. Erdwurm will address rate case expense.

Q. What is the basis of your testimony in this case?

A. I performed a regulatory audit of the Company's application and records. The regulatory audit consisted of examining and testing financial information, accounting records, and other supporting documentation and verifying that the accounting principles applied were in accordance with the Commission-adopted Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts ("USOA").

Q. How is your testimony organized?

A. My testimony is presented in four sections. Section I is this introduction. Section II provides a background of the Company. Section III is a summary of the Company's filing and RUCO's rate base, and operating income adjustments, and Section IV presents RUCO's operating income recommendations.

II. BACKGROUND

Q. Please review the background of this application.

A. TEP is classified as a class "A" utility. TEP is a for-profit, certificated Arizona public service corporation that provides electric utility service to various communities in Pima County, Arizona. On June 17, 2022, TEP filed an application with the Commission for a permanent rate increase. The TEP corporate business office is located at 88 East Broadway Blvd., Tucson, AZ 85702.

Q. Can you provide additional background on UNS' corporate structure?

A. UNS Energy is a subsidiary of Fortis Inc., the largest investor-owned electric and gas distribution utility in Canada. UNS Energy is based in Tucson, Arizona and is the parent company of both TEP and UniSource Energy Services ("UES"). TEP serves more than 432,000 customers in and around Tucson, while UES provides natural gas and electric service to about 256,000 customers in northern and southern Arizona. Electric service is provided through a UES subsidiary called UNS Electric, Inc., while natural gas service is provided through a subsidiary called UNS Gas, Inc.

Q. What is the test year that the Company has selected?

A. The Company has selected a test year ended December 31, 2021.

Q. Has the Company *not* asked for recovery of an expense item as it did in its prior rate case?

A. Yes. Directors & Officers ("D&O") Liability Insurance.

Q. What is D&O Liability Insurance?

A. D&O Liability Insurance is liability insurance that covers directors and officers for claims made against them by shareholders or others for decisions they may make within the scope of their responsibilities.

Q. Did RUCO ask the Company for the amount incurred by Fortis the parent Company and amount that was allocated to TEP in the test-year?

A. Yes, in RUCO data request 4.02.

Q. What was the Company's response?

A. The Company stated in response to RUCO data request 4.02:

> "*The Company objects to this request as irrelevant. D&O expense incurred by Fortis for its directors and officers is charged to TEP through the Fortis management fee.* ***TEP is not seeking recovery of Fortis management fees in this rate case.***"

III. SUMMARY OF FILING, RECOMMENDATIONS, AND ADJUSTMENTS

Q. Please summarize the Company's proposals in this filing.

A. The Company-proposed rates, as filed, produce total operating revenue of $1.330 billion, an increase of $234.111 million or a 21.36 percent increase, over adjusted test year revenue of $1.096 billion. The Company-proposed revenue will provide operating income of $275.844 million and a 5.25 percent rate of return on its proposed $5.251 billion fair value rate base ("FVRB").

RUCO recommends rates that produce total operating revenue of $1.228 billion, an increase of $132.776 million or a 12.11 percent increase, over the RUCO-adjusted test year revenue of $1.096 billion. RUCO's recommended revenue will provide operating income of $236.068 million and a 4.65 percent return on the $5.072 billion RUCO-adjusted FVRB (see RUCO Schedule 1).

Q. For the purposes of this rate case, has RUCO accepted the Company's gross revenue conversion factor of 1.3381?

A. Yes, as shown in RUCO Schedule 2.

Q. Has the Company asked for a fair value increment on its FVRB?

A. Yes. Mr. Cassidy, in his testimony, discusses why the Company should not be entitled to an increase in non-investor funds.

Q. Please summarize RUCO's rate base adjustments.

A. The five rate base adjustments are presented below and also discussed in the testimony of RUCO witness Crystal Brown:

<u>Rate Base Adjustment No. 1 – Post-Test Year Routine Plant</u> – This adjustment removes post-test year plant in the amount of $830,608 that was placed into service that RUCO deems as routine and not necessary under criteria that the Commission identified in Decision No. 71410.

<u>Rate Base Adjustment No. 2 – Post-Test Year Plant Retirements</u> – This adjustment removes plant retirements and accumulated depreciation related to plant that was retired from January 1, 2022, through June 30, 2022, in the amount of $89,954,490 for OCRB.

Rate Base Adjustment No. 3 – Accumulated Depreciation – This adjustment removes accumulated depreciation related to RUCO's plant adjustments. This adjustment decreases OCRB accumulated depreciation by $3,200,812.

Rate Base Adjustment No. 4 - Cash for Working Capital – This adjustment decreases cash working capital as a result of reflecting RUCO's recommended operating expenses and expense lag days in its cash working capital calculation. This adjustment decreases cash working capital by $1,005,564.

Rate Base Adjustment No. 5 – Remove Regulatory Assets – This adjustment decreases the regulatory assets by $35,392,313 to remove the Company's proposed regulatory assets and to increase the ADIT balance by $7,724,585 to remove the related ADIT adjustment.

Q. Please summarize RUCO's operating revenue and expense adjustments that you are sponsoring.

A. RUCO's thirteen operating income adjustment(s) are presented below:

Operating Income Adjustment No. 1 – Payroll Expense – Not used at the time of this filing.

Operating Income Adjustment No. 2 – Payment Card Processing Fees – This adjustment reverses payment card processing fees in the amount of $2,744,491 that the Company wants to spread to all customers, including those who do not pay their bills with credit/debit cards.

Operating Income Adjustment No. 3 – Board of Directors Fees – This adjustment recognizes that Board of Directors Fees benefit both ratepayers and shareholders and therefore RUCO recommends a 50/50 sharing of this cost. This adjustment reduces adjusted test year Board of Directors Fees by $356,137.

Operating Income Adjustment No. 4 – Short-Term Incentive Program – This adjustment recognizes known and measurable expenses and benefits both ratepayers and shareholders and therefore RUCO recommends a 50/50 sharing of this cost. This adjustment reduces the adjusted test year short-term incentive program expense by $4,469,854.

Operating Income Adjustment No. 5 – Long-Term Incentive Program – This adjustment removes costs that benefit the shareholders of the Company. This adjustment reduces the adjusted test year long-term incentive program expense by $2,735,258.

Operating Income Adjustment No. 6 – Supplemental Executive Retirement Plant ("SERP") Expense – This adjustment removes SERP expense that RUCO believes should not be borne by ratepayers, and is not necessary for the provision of electric services. This adjustment reduces SERP expense by $1,459,808.

Operating Income Adjustment No. 7 – Severance Pay – This adjustment removes items that RUCO believes should not be borne by ratepayers, and is not necessary for the provision of electric services. This adjustment reduces severance pay by $907,395.

Operating Income Adjustment No. 8 – Industry and Membership Dues – This adjustment recognizes that industry expenses benefit both ratepayers and shareholders and therefore RUCO recommends a 50/50 sharing of this cost. This adjustment reduces industry dues by $607,375.

Operating Income Adjustment No. 9 – Other Membership Dues – This adjustment removes other membership dues that are not necessary for the provision of electric services. This adjustment reduces the Other Membership Dues expense by $96,986.

Operating Income Adjustment No. 10 – Depreciation Expense – This adjustment reduces depreciation expense by $35,203,991 and is related to the adjustments previously mentioned above in RUCO's summary of rate base adjustments.

Operating Income Adjustment No. 11 – Rate Case Expense – RUCO recommends that the Company's rate case expense of $1,270,000 be allocated in a different manner as described in RUCO's rate design testimony.

Operating Income Adjustment No. 12 – Interest Synchronization Expense – This adjustment synchronizes interest expense based on RUCO's recommended rate base and weighted cost of debt and increases adjusted test year taxes by $515,731.

Operating Income Adjustment No. 13 – Income Tax Expense – This adjustment increases income tax by $12,102,232 to account for RUCO's adjustments to operating revenues and expenses.

IV. RATE BASE

Fair Value Rate Base ("FVRB")

Q. Did the Company prepare a schedule showing the elements of a Reconstruction Cost New Depreciated ("RCND") Rate Base?

A. Yes. The Company derived its FVRB by taking the average of the Original Cost Rate Base ("OCRB") and RCND. This methodology has been accepted by the Commission in prior decisions.

Q. Has RUCO presented its schedules to reflect OCRB, RCND and FVRB?

A. Yes. For purposes of this presentation, RUCO has used the Company's OCRB information as the starting point for RUCO's determination of the Company's FVRB.

Rate Base Summary

Q. Please summarize RUCO's adjustments to the Company's OCRB.

A. RUCO's adjustments to the Company's rate base resulted in a net decrease of $122,659,202, from $3,625,147,888 to $3,502,488,686 the decrease was primarily due to the following RUCO adjustments: (1) Post-Test Year Routine Plant, (2) Post-Test Year Retirements, (3) Accumulated Depreciation, (4) cash working capital, and (5) removal of regulatory assets, as shown on RUCO Schedules 4 and 5.

Q. For those RUCO adjustments that affect not only the OCRB but also RCND, has RUCO also presented this information?

A. Yes, if an adjustment affects not only the OCRB, but also the RCND, RUCO has shown the effects on the same schedule.

For an in-depth discussion of the individual rate base adjustments please see the Direct Testimony of RUCO witness Mrs. Crystal Brown.

V. OPERATING INCOME

Operating Income Summary

Q. What are the results of RUCO's analysis of test year revenues, expenses, and operating income?

A. RUCO's analysis resulted in adjusted test year operating revenues of $1,096,191,843, operating expenses of $959,344,574 and operating income of $136,847,270, as shown on RUCO Schedules 13 and 14. RUCO made thirteen adjustments to operating income, as presented below.

Operating Income Adjustment No. 1 – Payroll Expense

Q. Did the Company, in its last rate case, ask ratepayers to pay for estimated employee salaries increases two years past the test year?

A. Yes.

Q. Is the Company proposing the same in this rate case?

A. No.

Q. What is the Company proposing in this case?

A. Based on the Company's Pro-forma Income – Payroll and Benefits adjustment, the Company is proposing a 3.00 percent increase for 2022 and a 3.00 percent increase for 2023 for unclassified workers. The Company is also proposing a 2.75 percent increase for 2022 and a 3.00 percent increase for 2023 for union workers, as illustrated in the table below:

TEP Unclassifed	Merit Budget	EE Count	Total Actual	Notes
2021	2.00%	874	2.11%	
2022	3.00%	832	2.90%	
2023	3.00%	830		Projected
TEP Classifed (Union)	**Wage Budget**	**EE Count**	**Total Actual**	**Notes**
2021	2.95%	801	2.95%	Count as of 1/1/21; transitioned many SES union to TEP union
2022	2.75%	797	2.75%	Count as of 1/1/22
2023	3.00%	790		Projected
	Combined Avg	**Weighted Classified**		
actual 2022	2.82%			
projected 2023	3.00%	1.46%		

Q. Please briefly explain the Company's methodology.

A. The Company averaged the 2020 amount of $102,588,610 and 2021 amount of $105,821,948 Operations and Maintenance ("O&M") wages to derive O&M wages of $104,205,279. The Company next increased this total by 2.82 percent (the combined average in the table above) to increase O&M wages to $107,147,312 the estimated 2022 amount, and finally increased the $107,147,312 by 1.46 percent (the Union amount only in 2023) to derive the estimated 2023 amount of $108,714,839. The result is an increase of $4,940,752 (i.e., $93,964,269 - $89,023,517) or 5.55 percent. When the percentage that must be allocated to capital $(467,286) and the increase to pension and benefits $658,483 are reflected, the net result is $5,131,948 (i.e., $4,940,752 - $467,286 + $658,483 = $5,131,948). This amount is then allocated using the ACC jurisdictional ratio of .808316 for a total pro-forma adjustment of $4,148,239.

Q. What did the Commission state in Decision No. 77856 (dated 12/31/20)?

A. The Commission stated, *"We agree with Staff's reasoning and adopt its recommendation to disallow TEP's proposed 2.725 percent wage increase for non-union employees in 2020."*

Q. Does RUCO agree with the Company's calculation of the Pro-forma amount?

A. No. The Union percentage is not known and measurable at this time. However, the Company's position is consistent with Decision No. 77856.

Q. What is RUCO's recommendation?

A. RUCO recommends no changes for now, however, a true-up may be necessary in Surrebuttal testimony, and TEP must provide the union contract authorizing the 3.00 percent increase for union employees for 2023.

Operating Income Adjustment No. 2 – Reverse Payment Card Processing Fees

Q. Has the Company proposed that all customers pay for payment processing fees even if they do not use the service, yet again?

A. Yes.

Q. What has the Company proposed in this case for payment processing fees?

A. The Company has proposed to spread the credit and debit card processing fees to all customers, as the Company stated:

> "Many of our customers have expressed frustration over TEP's practice of charging fees for credit or debit card payments. These fees pose a particular burden to low-income customers, particularly those without bank accounts who cannot send checks through the mail or make free online payments through our website or mobile app. These forms of payments require third-party service providers, and the costs of these services are borne by customers, as they are not currently included in our rates. The Company is asking for the flexibility to revise its payment policy and eliminate most fees currently paid for by customers if they choose to pay their bill by credit or debit card, or in-person at Walmart or other retail locations."[1]

[1] See the Direct Testimony of Company Witness Lynne Peterson, page 10, lin13.

Q. What is the amount that the Company is requesting be recovered by all ratepayers in this case?

A. Based on the Company's Pro-forma Income – Payment Processing Fees adjustment the Company is requesting $2,744,491 as illustrated in the table below:

	TEP Year Summary		2021 Total	Cost/Transaction	Estimated Cost (test year volume)	Estimated Cost (Year 1)	Est. % Inc. - Year 1	Est. % Inc. - Year 2	Est. % Inc. - Year 3
Walk-in	CHECKFREE	Tot. Payments	62,182	$1.50 - $ 2.99	$ 124,364	$ 217,637	50%	75%	100%
Credit/Debit	KUBRA	Tot. Payments		$1.95 / $9.95		$ 2,309,324	50%	75%	100%
Walk-in	WESTERN UNION	Tot. Payments	49,721	$1.95 - $2.99	$ 124,303	$ 217,529	50%	75%	100%
						$ 2,744,491			
					Pro forma adjustment				

Q. In essence has the Company continued to advocate for the "socialization" of these payment costs?

A. Yes. This proposal, which the Company refers to as "socialization,"[2] is inconsistent with the cost causation principle, which requires that costs be borne by the customers who cause the utility to incur the cost (i.e., cost-causers).

Q. Has the Company advanced this socialization policy in its prior two rate cases?

A. Yes. In Docket Nos. E-01933A-15-0322 and E-01933A-19-0028.

Q. Was there ever a fully litigated decision in those cases?

A. No. Docket No. E-01933A-15-0322 resulted in a settlement agreement, and the payment processing fees were withdrawn before the hearing in Docket No. E-01933A-19-0028.

Q. Did the Company acknowledge that there are no cost ways for customers to pay their bills, as it did in prior rate cases?

A. Yes, the Company acknowledged in response to RUCO data request 6.06(a) that:

---

[2] Ibid, page 14, line 7.

> "Auto Pay is a free payment option that allows a customer to have their bill automatically paid by/deducted from the customer's checking or savings account."

Further, the Company admitted that:

> "Auto Pay is a customer choice and convenience payment offering that helps them avoid paying for postage or **one-time transaction fees from a third party**. Customers must choose to enroll in this payment option as the Company does not automatically enroll anyone on Auto Pay. We believe customers enrolled in Auto Pay are customers who choose to pay timely regardless of payment options."

Q. What is RUCO's recommendation?

A. RUCO recommends denial of this unnecessary cost shift because it is not based on cost of service – cost causation; second, the adjustment incorporates estimates of future years that are not known and measurable; third, the Company has not shown that they are harmed financially under the current methodology; fourth, the adjustment discriminates unnecessarily among customer classes; and fifth, a fundamental tenet of sound ratemaking is to avoid cross subsidization when possible and especially when there is no sound policy justification. RUCO has reversed the Company's latest proposal and eliminated the payment processing fees again in the amount of $2,744,491, as shown in RUCO Schedule 16.

Q. Any concluding remarks?

A. Yes. The Company could offer a small discount or one time discount to those customers who sign-up or use TEP Auto Pay and TEP e-bill. This could be both a benefit for the Company and customers. The Company would benefit by reducing the billing processing costs. The Company indicated in response to RUCO data request 6.08 (a), that "The average cost for printing and mailing a bill is $0.64 compared to $0.01 for e-bill." This would also address the one-time transaction fees from third-party payment processing companies.

Operating Income Adjustment No. 3 – Board of Directors Fees

Q. Has the Company asked to recover 100 percent of its Board of Directors Fees from ratepayers?

A. Yes.

Q. What is the amount that the Company is seeking to recover from ratepayers?

A. Based on the Company's response to RUCO data request 1.46, the Company is seeking a total of $824,009, and $712,273 on an ACC jurisdictional basis.

Q. Whose interest do the Board of Directors ("Board") represent?

A. In general, the Board sets broad policies and makes important decisions as a **fiduciary** on behalf of the **Company** and its **shareholders**.

Q. Did RUCO also ask if any of the Board of Directors also held stock in Fortis Inc.?

A. Yes, in RUCO data request 4.06.

Q. What was the Company's response?

A. The Company stated in their response to RUCO data request 4.06:

> "The Company objects to the question as irrelevant. However, without waiver of objection, to the Company's knowledge current UNS Energy Corporation Directors James Reid, Jocelyn Perry and Gary Smith own Fortis stock, the amounts of which are reported and available in Fortis' publicly filed reports. UNS Director Susan Gray also owns Fortis stock, the specific number of which is not publicly available. The Company does not have information on whether the remaining directors own Fortis stock since ownership is not required nor a component of their compensation."

Q. Does RUCO agree that this information is irrelevant?

A. No. Several of UNS Board of Directors are identified as Fortis Inc. insiders, which is public information. Also, several of the Board of Directors at the UNS Energy level are also on the Board of Directors at the Fortis Inc. level. As a result, the directors may not be acting primarily in the interest of ratepayers, but rather in the interest of the Company and shareholders.

Q. How has the Commission treated Board of Directors fees recently?

A. The Commission in Decision No. 78644 (dated July 27, 2022) stated:

> "Neither RUCO nor Staff argues that compensating a board of directors is an inappropriate expense to be recovered from ratepayers. We agree that having a board of directors is a cost of doing business as a publicly traded company. The benefits noted by the Applicants from being listed on a major stock exchange, such as refinancing debt, reducing interest rates by 200 basis points, raising $37 million in new equity, and establishing a platform to raise additional capital at favorable rates when needed, require GWRI to have a board of directors. Because it is a cost of doing business for which there is insufficient evidence demonstrating it primarily benefits ratepayers or shareholders, we find that Staff and RUCO's recommendation of a 50/50 sharing is reasonable. For that reason, we adopt Staff's recommended adjustment removing 50% of board cash and DSU compensation and disallowing 100% of unrealized gain on DSUs from Miscellaneous expense."[3]

Q. Did the Public Utilities Commission ("PUC") of Nevada also agree that the board of directors' compensation be shared equally between ratepayers and shareholders?

A. Yes, in Docket No. 20-02023 (Southwest Gas Corporation) the PUC of Nevada stated the following:

---

[3] See page, 84 line 3 of Decision No. 78644.

> "Regarding BOD expenses, the Commission accepts Staff and BCP's recommendation to disallow 50 percent of the BOD expenses in order to share the costs equally between ratepayers and shareholders. The Commission finds that the evidence on the record supports benefits to both ratepayers and shareholders. In SWG's last GRC, the Commission allocated SWG's BOD compensation equally between shareholders and ratepayers, however, the Commission did not address Board meeting costs or expenses. **The Commission finds that because it is reasonable to split expenses equally between ratepayers and shareholders, as well, given that both groups benefit from the actions of BOD. The BOD's oversight is intended to ensure that SWG is operating in a manner that will result in safe, reliable, and adequate service, which benefits ratepayers. Efficient operation of the Board should also increase the value of SWG, which benefits shareholders in the form of increased stock value and earnings per share.** The reasonable costs of the Board meetings themselves, including the costs for airfare and vehicle transportation, hotel accommodations and meal expenses, are most reasonably split equally between ratepayers, and shareholders."[4] (Emphasis added)

Q. What is RUCO's recommendation?

A. Based on the fiduciary duty to shareholders, and recent Commission Decisions, RUCO recommends a 50/50 sharing of Board of Directors Fees, as shown in RUCO Schedule 17.

Operating Income Adjustment No. 4 – TEP Short-Term Incentive Program or Performance Enhancement Program ("PEP")

Q. Has the Company asked for ratepayers to fund 100 percent of its incentive compensation program yet again?

A. Yes.

Q. Briefly describe the PEP?

A. According to the Company's response to Uniform Data Request ("UDR") Employee Compensation and Benefit Information ("ECB") - 1.013, Incentives:

---

[4] https://pucweb1 .state.nv.us/PUC2/DktDetaiI.aspx

> "All TEP non-union employees participate in UNS's short-term incentive program ("PEP"), which is tied to annual compensation.
>
> The PEP performance targets and weighting are based on factors that are essential for the long-term success of the Company and are identical to the performance objectives used in its performance plan for other non-union employees. In 2021, the objectives were (i) Efficient Growth; (ii) Valued Customers; (iii) Thriving Employees; and (iv) Social Impact, which include both quantitative and qualitative measures. The Compensation Committee of the Board of Directors selected the goals and individual weightings for the 2021 PEP to ensure an appropriate focus on profitable growth and expense control, as well as operational and customer service excellence, safety and inclusivity for employees, and sustainability. **This balanced scorecard approach encourages all employees to work toward common goals that are in the interests of UNS's various stakeholders [emphasis added].** The outcomes of these efforts all benefit our customers in the long run.
>
> The financial and other metrics for the Company's 2021 Short-Term Incentive Compensation program were:
>
> - Efficient Growth – 40%
>   - Net Income – 30%
>   - Cash Flow from Operations – 10%
> - Valued Customers – 25%
>   - System Average Interruption Duration Index (SAIDI) – 10%
>   - Performance on JD Power Survey – 10%
>   - O&M – 2021 Actuals vs. Target – 5%
> - Thriving Employees – 25%
>   - Safety Report Responses – 10%
>   - Total Recordable Incident Rate – 5%
>   - Diversity, Equity & Inclusion (DEI) – 10%
> - Social Impact – 10%
>   - Sustainability – 10%"

Q. What is the total amount of the PEP expenses reported in UDR Internal and External Reporting ("IER") - 1.016 presumably the 40 percent that the Commission disallowed in the last rate case?

A. The Company states this amounted to $4,573,003 in overall expenses, and $3,823,356 in Arizona Jurisdictional expenses.

Q. What is the amount reported for the test year?

A. Based on the Company's pro-forma adjustment the amount is $10,850,555.

Q. Did RUCO ask the Company to reconcile these two numbers?

A. Yes, in RUCO data request 6.1.

Q. Please reconcile the differences between the two amounts?

A. Based on the Company's response to RUCO Data Request 6.1, the pre-jurisdictional amount shown in the UDR of $3,573,003 represents 40 percent of the 3-year average of short-term incentive compensation expense for the years ended December 31, 2019 ($10,422,075), 2020 ($10,690,381) and Test Year 2021 ($11,059,723).

Derived as follows: (10,422,075+10,690,381+11,059,723)/3 = $10,724,060 *.40 = $4,289,624 plus payroll tax $32,172,189 = $4,573,003.

Q. Did the Company also decrease the test year amount of $10,850,556 by $97,759 to normalize it to the three-year average of $10,724,060?

A. Yes.

Q. Does PEP benefit both ratepayers and shareholders?

A. Yes. As the Company stated above.

Q. Has the Commission historically recognized this concept?

A. Yes.

> Decision No. 68487 (dated February 23, 2006) – *"In Decision No. 64172, the Commission adopted Staff's recommendation regarding MIP expenses*

based on Staff's claim that two of the five performance goals were tied to return on equity and thus primarily benefited shareholders. We believe that Staff's recommendation for an equal sharing of the costs associated with MIP compensation provides an appropriate balance between the benefits attained by both shareholders and ratepayers. Although achievement of the performance goals in the MIP, and the benefits attendant thereto, cannot be precisely quantified, there is little doubt that both shareholders and ratepayers derive some benefit from incentive goals. Therefore, the costs of the program should be borne by both groups and we find Staff's equal sharing recommendation to be a reasonable resolution."[5]

Decision No. 70011 (dated November 27, 2007) - *"We believe that Staff's recommendation provides a reasonable balancing of the interests between ratepayers and shareholders by requiring each group to bear half the cost of the incentive program. As RUCO points out, the program is comprised of elements that relate to the parent company's financial performance and cost containment goals, matters that primarily benefit shareholders."*[6]

Decision No. 70360 (dated May 27, 2008) - *"Consistent with our finding in the UNS Gas rate case (Decision No. 70011 at 26-27), we believe that Staff's recommendation provides a reasonable balancing of the interests between ratepayers and shareholders by requiring each group to bear half the cost of the incentive program."*[7]

Decision No. 70665 (dated December 24, 2008) - *"in the last Southwest Gas rate case, as well as several subsequent cases we disallowed 50 percent of management incentive compensation on the basis that such programs provide approximately equal benefits to shareholders and ratepayers because the performance goals relate to Financial performance and cost containment goals as well as customer service elements. (Decision No. 68487 at 18.) In that Decision, we stated: In Decision No. 64172, the Commission adopted Staff's recommendation regarding MIP expenses based on Staff's claim that two of the five performance goals were tied to return on equity and thus primarily benefited shareholders. We believe that Staff's recommendation for an equal sharing of the costs associated with MIP compensation provides an appropriate balance between the benefits attained by both shareholders and ratepayers. Although achievement of the performance goals in the MIP, and the benefits attendant thereto, cannot be precisely quantified, there is little doubt that both shareholders and ratepayers derive some benefit from incentive goals. Therefore, the costs of the program should be borne by both groups and we find Staffs equal sharing recommendation to be a reasonable resolution. (Id.) We believe*

[5] See page, 18 line 4 of Decision No. 68487.

[6] See page, 27 line 1 of Decision No. 70011.

[7] See page, 21 line 1 of Decision No. 70360.

the same rationale exists in this case to adopt the position advocated by Staff and RUCO to disallow 50 percent of the Company's proposed MIP costs."[8]

Decision No. 71914 (dated September 30, 2010) - *"We believe that the Staff and RUCO recommendations, to require a 50/50 sharing of incentive, compensation costs, provide a reasonable balancing of the interests between ratepayers and shareholders. The equal sharing of such costs recognizes that the program is comprised of elements that relate to the parent company's financial performance and cost-containment goals, matters that primarily benefit shareholders, while at the same time recognizing that a portion of the program's incentive compensation is based on meeting customer service goals. This offers the opportunity for the Company's customers to benefit from improved performance in that area."*[9]

Decision No.77147 (dated April 16, 2019) – *"We also believe that the interim revenue increases should not be higher than those authorized in the ROO, as corrected by EPCOR. In addition, at the January 25, 2019, Open Meeting, the Commission voted 3-to-l to pass an amendment splitting the incentive pay equally between ratepayers and shareholders. Thus, we find that the revenue requirements from the Districts should reflect a reduction in the incentive pay expense from 90 percent to 50 percent. This reduction for incentive pay shall also include a reduction from the allocated costs of incentive pay on the parent level."*[10]

Decision No. 77850 (dated December 17, 2020) – *"We agree with Staff and RUCO that incentive compensation based on profitability benefits shareholders and not ratepayers. As a result, we find that Staff's recommendation to disallow the 40 percent of the MIP related to net income is appropriate under the circumstances. Accordingly, we adopt Staffs proposed adjustment to MIP expense as well as the corresponding adjustments to tax."*[11]

Decision No. 78644 (dated July 27, 2022) – *"We agree with the Global Water Utilities that incentive compensation based solely on financial performance benefits shareholders and not ratepayers. To that end, we find that Staff's recommendation, which the Global Water Utilities accepted, to remove 100% of PSU compensation as it inures solely to the benefit of shareholders, is reasonable and should be adopted.*

---

[8] See page, 16 line 3 of Decision No. 70665.

[9] See page, 28 line 19 of Decision No. 71914.

[10] See page, 19 line 23 of Decision No. 77147.

[11] See page, 45 line 11 of Decision No. 77850.

We are not persuaded that the categorical metrics employed by the Applicants' incentive compensation plan achieves such a clearly delineated allocation of benefits between ratepayers and shareholders, however. The Global Water Utilities only recognize efficient service as a category that primarily benefits shareholders while they deem ratepayers to be the primary beneficiaries of strong customer service, safe operations, and prudent capital investments. We disagree. ***Shareholders also benefit from high performance in these categories. Excellent customer service avoids disputes and improves public good will toward the utility, while safe operations reduce the risk of work injuries and concomitant insurance costs. Further, prudent capital investments benefit the shareholder by ushering more plant into rate base on which returns can be earned [emphasis added]****. Just so, ratepayers also benefit from efficient service because greater efficiency translates into lower operating costs that must be recovered in utility rates.*

Testifying for the Global Water Utilities, Ms. Ellsworth explained the Applicants' view that for purposes of allocating performance incentive compensation costs, ratepayers are the primary beneficiary when the benefit obtained from the incentive is good specifically for customers. When asked to clarify the allocation of benefit between shareholders and ratepayers for each program category, however, Ms. Ellsworth admitted that shareholders benefit from good worker performance in each of the program categories.

For these reasons, we agree with RUCO's and Staffs position that a 50/50 sharing of nonexecutive incentive compensation is reasonable. Accordingly, we adopt Staff's recommended adjustments to Salary and Wages expense."[12]

Further, in some rate cases performance pay or bonus pay has been completely disallowed by the Commission.

<u>Decision No. 71865 (dated August 31, 2010)</u> - *"We agree with Staff that the performance pay, or bonus pay, should not be included as part of expenses included in rates."*[13]

<u>Decision No. 74568 (dated June 20, 2014)</u> - *'We agree with Staff that the Company failed to quantify or justify its proposed recovery of incentive pay,*

---

[12] See page, 80 line 20 of Decision No. 78644.

[13] See page, 27 line 8 of Decision No. 71865.

> *and disagree with RUCO that half of the incentive pay request should be allowed."*[14]

(Footnotes From Decisions Cited Omitted).

Q. What did the Commission conclude in the Company's last rate case, Decision No. 77850 (dated December 31, 2020)?

A. "We agree with Staff, AECC, and RUCO that incentive compensation based on profitability benefits shareholders - not ratepayers, thus, that portion of the PEP expense should be eliminated from Payroll Expense. Further, we agree with Staff's conclusion that removal of 40 percent of PEP expense is the appropriate adjustment for this expense. Accordingly, we find that 40 percent of TEP's proposed PEP expense should be removed."[15]

Q. Does setting up an "at risk" component that is added to the base salary of employees also benefit the Company?

A. Yes. For example, if it is determined that the market value of an employee is $60,000, the at-risk portion is $10,000 and base salary is $50,000, and the employee is terminated halfway through the year the Company would have only paid $25,000 instead of $30,000. Then obviously, the Company's forecasted market value was overestimated, and this at-risk component adds a safeguard for the Company.

Likewise, the Company controls the amount of the PEP bonus paid. If the employee is underperforming, little or no bonus may be given. If the employee is over performing a larger bonus may be given.

---

[14] See page, 25 line 14 of Decision No. 74568.
[15] See page 85, line 1 of Decision No. 77856.

In addition, the at-risk component also provides the Company with financial flexibility in the event of a cash flow shortage. The Company can pay lower PEP bonuses or depending on the situation, give no PEP bonus. Any portion of the PEP bonuses not awarded would flow to the shareholders. As noted in the Company's last rate case, the Company, in its discretion, may adjust the amount of any Award payable pursuant to the Plan or may, in its discretion, determine that ***no Awards will be paid for a Plan Year***, ***commonly referred to as the funding level***. In addition, individual Awards may vary, at the sole discretion of the Company, based on the individual's performance and other factors.

Q. Has the Company offered any new testimony regarding the short-term incentive plan that would cause the Commission to depart from its long history of sharing the benefits of short-term incentive pay or in some cases not authorizing any short-term incentive pay?

A. No.

Q. What is RUCO's recommendation?

A. RUCO recommends that short-term incentive compensation expense be reduced by 50 percent or $4,469,854 after application of the ACC jurisdictional ratio, as shown in RUCO Schedule 18.

Operating Income Adjustment No. 5 – Long-Term Incentive ("LTI") Compensation Program

Q. Has the Company asked for ratepayers to fund 100 percent of its Long-Term Incentive compensation yet again?

A. Yes.

Q. Briefly describe the LTI Compensation Program?

A. "The Long-Term Incentive Compensation ("LTI") program is comprised of Performance Share Units ("PSU") and Restricted Stock Units ("RSU"). The program is designed to: (1) place a focus on long-term performance, linking a portion of the compensation of executive officers to the achievement of multi-year financial results, and (2) serve as a retention tool for executive talent. These objectives are achieved by a three-year vesting schedule inherent in each annual LTI award. The PSUs will result in cash compensation to the extent that the three-year cumulative financial target is achieved. RSUs also pay out in cash and vest over three years to serve as a retention tool, officers may request RSUs be paid out in Fortis Stock in lieu of cash."[16]

Q. What is the amount of LTI expense that the Company is requesting to be recovered by ratepayers in this case?

A. The Company in UDR 1.016c indicated a total of $3,164,190 on a company-wide basis and $2,735,258 on a jurisdictional bias.

Q. What was the amount recorded in the test year?

A. Based on the Company's pro-forma LTI adjustment the test year amount is $3,075,005.

Q. Did RUCO ask the Company to reconcile these two numbers?

A. Yes, in RUCO data request 6.2.

Q. Please explain the differences in the two amounts?

A. Based on the Company's response to RUCO Data Request 6.2, the pre-jurisdictional amount shown in the UDR of $3,164,190 represents the 3-year average of long-term incentive

---

[16] See the Direct Testimony of Company Witness Brian F. Brumfield, page 19, line 1.

compensation expense recorded in FERC 920 for the years ended December 31, 2019 ($3,423,953), 2020 ($2,993,611) and the Test Year 2021 ($3,075,005).

Q. Did the Company also increase the test year amount of $3,075,005 by $89,185 to normalize it to the three-year average of $3,164,190?

A. Yes.

Q. Who is eligible for the LTI?

A. According to Company UDR ECB 1.014, Officers of UNS who provide services to TEP are eligible to participate in the long-term incentive program.

Q. What concerns does RUCO have with the LTI expense?

A. They are the same concerns RUCO expressed in the last several rate cases filed by TEP.

First, the LTI expense is already limited to adequately compensated individuals.

Second, unlike the short-term incentive PEP program mentioned above, the compensation is tied to financial performance, which benefits the Company and its shareholders. There is nothing tied to benefits like reliability and quality of service for its ratepayers.

Third, if the program is successful and generates additional earnings for the Company, the Company should use its earnings to fund the on-going program, and not ask that the burden be placed 100 percent on ratepayers.

Fourth, the LTI compensation of the Company executive is tied to a three-year period related to the financial statements and to the Company's stock price, this creates an incentive for the employee to make business decisions from the perspective of shareholders, and therefore, there is an alignment of interest between the Company executives and its shareholders.

Fifth, and perhaps most importantly, ratepayers should not have to pay for several plans which serve the same purpose – rewarding executive compensation.

RUCO believes it is not appropriate to ask ratepayers to bear the costs of incentive plans designed to encourage utility executives to put the financial interest of its shareholders ahead of its ratepayers. Especially since the financial statements are strengthened by increases in utility rates and underlying adjustor mechanisms. Higher rates are beneficial for shareholders while higher rates are detrimental to ratepayers.

While cost containment is important to ratepayers, RUCO expects the Company, as part of the regulatory compact, to act in the best interest of its customers and control costs with or without an incentive compensation program.

Q. Does it matter if the LTI plan is reasonably benchmarked with other peers?

A. No, it does not matter that the Company's financial-based incentives are set at a reasonable level, if it is determined by the Commission that these costs are not reasonable for ratemaking purposes, as this Commission has done in the past.

Q. How has the Commission treated LTI plans in the past?

A. <u>Decision No. 70360 (dated May 27, 2007)</u>:

> *"We agree with Staff that test year expenses should be reduced to remove stock-based compensation to officers and employees. As Staff witness Ralph Smith stated, the expense of providing stock options and other stock-based compensation beyond normal levels of compensation should be borne*

> *by shareholders rather than ratepayers (Ex. S-58, at 34). The disallowances of stock-based compensation are consistent with the most recent rate case for Arizona Public Service Company (Decision No. 69663.)"*[17]

> <u>Decision No. 77850 (dated December 17, 2020)</u> – *"We find that the RSUP is exclusively tied to the Company's future financial results and that the associated costs should therefore be disallowed, as both Staff and RUCO recommend. To the extent that shareholders wish to compensate SWG management for its enhanced earnings, they may do so, but it is not appropriate for the utility's ratepayers to provide such incentive and compensation. Accordingly, we adopt the adjustment proposed by Staff and RUCO."*[18]

Q. Did the Company request recovery of LTI costs in its last rate case?

A. Yes.

Q. What did the Commission decide in Commission Decision No. 77856 (dated December 31, 2020) TEP's last rate case.

A. The Commission stated:

> "Based on the arguments presented, we find that it is reasonable to exclude LTI program costs from operating expenses."

Q. Has the Company offered any new testimony in regard to the LTI Compensation Plan, that would cause the Commission to depart from its long-history of removing all of the LTI pay?

A. No.

---

[17] See page, 22 line 22 of Decision No. 70360.

[18] See page, 46 line 20 of Decision No. 77850.

Q. What is RUCO's recommendation?

A. RUCO recommends the removal of all LTI expense in the amount of $2,735,258, as shown in RUCO Schedule 19.

Operating Income Adjustment No. 6 – Supplemental Executive Retirement Plan ("SERP") Expense

Q. What is a SERP?

A. The Company defines SERP as *"The qualified pension retirement plan, which covers all TEP employees, is subject to IRS limitations on the amount of compensation that can be taken into account on the amount of benefits that can be provided. The non-qualified SERP provides the retirement benefits to executive officers that would have been provided under the qualified retirement plan had the limitations not applied."*[19]

Q. What is the amount of SERP expense that the Company is requesting be recovered by ratepayers in this case?

A. The Company in UDR IER 1.016c indicated a total of $1,688,728 on a company wide basis and $1,459,808 on a jurisdictional bias.

Q. What was the amount reported on the actuary report for TEP?

A. $1,990,486.

Q. Did RUCO ask the Company to reconcile these two numbers?

A. Yes, in RUCO data request 6.3.

Q. Please explain the differences in the two amounts?

A. The Company stated in response to RUCO data request 6.3:

[19] See the Direct Testimony of Company witness Brian F. Brumfield, page 13, line 5.

> "The difference between the TEP SERP amount of $1,990,486 per actuary report and the prejurisdictional amount of $1,688,728 per UDR is due to allocations to UNS Gas and UNS Electric."

Q. Does RUCO agree that ratepayers should pay for these costs?

A. No. RUCO does not consider the cost of supplemental benefits for high-ranking officers necessary to the provision of electric service. Company officials are already fairly compensated for their work and are provided with a wide array of benefits including a medical plan, dental plan, life insurance, long term disability, paid absence time, and a retirement plan. RUCO believes that any excess or additional perks given to a select group of employees should be borne by the Company's shareholders, and not ratepayers.

Q. Has the Commission disallowed SERP in prior rate decisions?

A. Yes.

> <u>Decision No. 68487 (dated February 23, 2006)</u> – *"We agree with RUCO's position on this issue. Although we rejected RUCO's arguments on this issue in the Company's last rate proceeding, we believe that the record in this case supports a finding that the provision of additional compensation to Southwest Gas' highest paid employees to remedy a perceived deficiency in retirement benefits relative to the Company's other employees is not a reasonable expense that should recovered in rates. Without the SERP, the Company's officers still enjoy the same retirement benefits available to any other Southwest Gas employee and the attempt to make these executives "whole" in the sense of allowing a greater percentage of retirement benefits does not meet the test of reasonableness. If the Company wishes to provide additional retirement benefits above the level permitted by IRS regulations applicable to all other employees it may do so at the expense of its shareholders. However, it is not reasonable to place this additional burden on ratepayers."*[20]

> <u>Decision No. 69663 (dated June 28, 2007)</u> - "*APS has not demonstrated any reason to treat the SERP expense for its SERP eligible employees any differently than our determination of SERP expenses associated with SWG*

[20] See page, 19 line 7 of Decision No. 68487.

employees. Accordingly, we find that the SERP expense should not be recovered from APS ratepayers, and accordingly, will reduce operating expense in the amount of $3,931,467."[21]

Decision No. 70011 (dated November 27, 2007) - *"We disagree with the Company's argument that disallowance of the SERP costs effectively allows the IRS to dictate what compensation costs should be recovered. As was clearly stated in the passage cited above, the issue is not whether UNS may provide compensation to select executives in excess of the retirement limits allowed by the IRS, but whether ratepayers should be saddled with costs of executive benefits that exceed the treatment allowed for all other employees. If the Company chooses to do so, shareholders rather than ratepayers should be responsible for the retirement benefits afforded only to those executives. We see no reason to depart from the rationale on this issue in the most recent Southwest Gas rate case, and we therefore adopt the recommendations of Staff and RUCO and disallow the requested SERP costs.*

More disturbing than the Company's advocacy on the relative merits of the SERP is the statement in its initial brief that "[h]ad UNS Gas been notified that SERP costs would not be allowed, it could have restructured its executive compensation package to take that into account. It would not be fair to hold UNS Gas to this new, unexpected standard." (UNS Initial Brief at 28.) Implicit in the Company's argument is the concept that "if we don't recover fully what we believe are our reasonable costs in our preferred manner, we'll simply shift those costs to another account to disguise the costs and ultimately ensure recovery." The approach to rate recovery seemingly advocated by UNS can serve only to increase the cynicism often expressed by ratepayers regarding the reasonableness of a given utility company's proposed rates and, if allowed, would at its essence turn the ratemaking process into a veritable regulatory version of "Three-Card Monte." We trust that in future rate applications, Staff and RUCO will explore thoroughly the merits of individual expenses sought by UNS, as well as other companies, to ensure that customers are paying rates that include only the costs necessary to provide quality service."[22]

Decision No. 70665 (dated May, 27, 2007) – As the Commission stated in this long dialogue:

"We disagree with the Company's argument that disallowance of the SERP costs effectively allows the IRS to dictate what compensation costs should be recovered. As was clearly stated in the passage cited above, and which

---

[21] See page, 27 line 13 of Decision No. 69663.

[22] See page, 28 line 8 of Decision No. 70011.

passage was quoted in the UNS Gas case (Decision No. 70011, at 28), the issue is not whether UNSE may provide compensation to select executives more than the retirement limits allowed by the IRS, but whether ratepayers should be saddled with costs of executive benefits that exceed the treatment allowed for all other employees. If the Company chooses to do so, shareholders rather than ratepayers should be responsible for the retirement benefits afforded only to those executives."[23]

And again, in Decision No. 70665 (dated December 24, 2008), *the Commission stated, "Southwest Gas also offers a Supplemental Executive Retirement Plan ("SERP") to select executives. The SERP provides supplemental benefits for high-ranking employees more than the limits placed by Internal Revenue Service ("IRS") regulations on pension plan calculations for salaries above specified amounts. (Ex. S-12 at 30-31.) We explained in the last Southwest Gas case:*

IRS regulations place limits on pension plan calculations for salaries exceeding $165,000 and thus salaries in excess of that level are not included in the pension calculation. Mr. Mashas stated that the SERP provides officers with a retirement benefit equal to 50 percent of the average of the last three years' salary if they are at least 60 years old and have at least 20 years of service. In addition, IRS regulations place restrictions on the Company's 401(k) contributions to the extent that "maximum contribution levels represent a significantly smaller percentage of an officer's salary compared to other employees.

[Decision No. 68487 at 18 (citations omitted).]

Company witness Hobbs testified that the MIP, SIP and SERP are "key components of [the Company's] prudently managed total executive compensation expense and are vital to the Company's attraction and retention of highly-skilled employees, which ultimately benefits customers." (Ex. A-8 8 at 7-8.) She explained that the SERP is an "unqualified plan," and therefore payments are not guaranteed. She also stated that contrary to the testimony provided by Staff and RUCO, virtually every other gas and electric utility offers such employees a SERP, and the costs. of the SERP are reasonable. (id.)

Staff witness Smith and RUCO witness Moore recommend a total disallowance of SERP expenses. Mr. Smith cites to the prior Southwest Gas rate case, as well as the subsequent UNS Gas, APS, and UNS Electric cases, wherein the Commission disallowed SERP costs. Mr. Moore stated that

[23] See page, 22 line 11 of Decision No. 70360.

SERP costs are not a necessary cost for providing service and indicated that the high-ranking officers covered by the SERP are already fairly compensated for their work and are provided a comprehensive array of benefits in addition to salaries. (RUCO Ex. 3 at 30.) We agree with Staff and RUCO that the SERP expenses sought by Southwest Gas should once again be disallowed. We do not believe any material factual difference exists in this case that would require a result that differs from the Company's prior case. In that case, we stated:

[W]e believe that the record in this case supports a finding that the provision of additional compensation to Southwest Gas' highest paid employees to remedy a perceived deficiency in retirement benefits relative to the Company's other employees is not a reasonable expense that should be recovered in rates. Without the SERP, the Company's officers still enjoy the same retirement benefits available to any other Southwest Gas employee and the attempt to make these executives "whole" in the sense of allowing a greater percentage of retirement benefits does not meet the test of reasonableness. If the Company wishes to provide additional retirement benefits above the level permitted by IRS regulations applicable to all other employees, it may do so at the expense of its shareholders. However, it is not reasonable to place this additional burden on ratepayers.

(Decision No. 68487 at 19.)

In the recent UNS Gas, APS, and UNS Electric cases, we followed the rationale cited above in disallowing SERP expenses. In Decision No. 7001l, we indicated that SERP costs should not be recoverable and indicated:

[T]he issue is not whether UNS may provide compensation to select executives more than the retirement limits allowed by the IRS, but whether ratepayers should be saddled with costs of executive benefits that exceed the treatment allowed for all other employees. If the Company chooses to do so, shareholders rather than ratepayers should be responsible for the retirement benefits afforded only to those executives. We see no reason to depart from the rationale on this issue in the most recent Southwest Gas rate case, and we therefore adopt the recommendations of Staff and RUCO and disallow the requested SERP costs.

[Id. at 28, (footnote omitted).]

For these reasons, we agree with the recommendations of Staff and RUCO that the request for inclusion in rates of SERP expenses should be denied. We therefore adopt the recommendations of Staff and RUCO on this issue."[24]

[24] See page, 16 line 18 of Decision No. 70665.

Likewise, in Decision No. 71914 (dated September 30, 2010), the Commission stated:

"We see no reason to depart from the rationale on this issue in all of the recent cases cited above, that ratepayers should not be required to fund the retirement benefits of a few select executives whose salaries exceed current IRS limits (currently $240,000). As has been stated in prior cases, the Company's shareholders may provide these additional retirement benefits but ratepayers should not be subject to this additional burden."[25]

Decision No. 77850 (dated December 17, 2020) – *The Commission stated: "We agree with Staff and RUCO that the proposed SERP expense is not a cost necessary to the provision of gas utility service to customers. To the extent that the Company wishes to provide additional retirement benefits above the level permitted by IRS regulations applicable to all other employees, the Company may do so, but at the expense of its shareholders. Although the Company claims that other utilities provide SERP for competitive compensation, the Company has not shown that other public utility commissions more frequently than not approve recovery of SERP. In this regard, we note that if SERP compensation in other jurisdictions is not included in the revenue requirement, then allowing it in Arizona would have the same effect as granting an above-market rate of return to SWG. Accordingly, we find that it is reasonable and appropriate under the circumstances to disallow the recovery of SERP expense in rates at this time."*[26]

Q. What did the Commission decide in Commission Decision No. 77856 (dated December 31, 2020) TEP's last rate case.

A. "The Commission disallowed SERP in the prior rate case. We agree with Staff that SERP related to income should be attributable to shareholders. Thus, we find that it is reasonable to disallow SERP in the amount of $1,170,000."[27]

---

[25] See page, 80 line 5 of Decision No. 71914.

[26] See page, 42 line 10 of Decision No. 77850.

[27] See page, 86 line 14 of Decision No. 77856.

Q. Are there any new arguments in this rate case that the Company has set forth?

A. No. TEP put forward the same arguments that have been rejected many times by the Commission in previous rate cases.

Q. What is RUCO's recommendation?

A. This request is yet another form of additional executive pay whose purpose is to add to the overly generous executive pay being requested and should be borne by the shareholders, not the ratepayers. RUCO recommends that $1,459,808 in SERP expenses be removed, as shown on RUCO Schedule 20.

Operating Income Adjustment No. 7 – Severance Pay

Q. Has the Company asked for severance pay in this case?

A. Yes, the Company stated in following in UDR ECB - 1.020:

> *"The Test year includes severance pay of $907,395 (all O&M); $869,618 was recorded in FERC Account 920 and $37,777 in FERC Account 408.1."*

Q. What is a severance pay?

A. Severance pay is defined by Meriam-Webster as: *"an allowance usually based on length of service that is payable to an employee on termination of employment."*

Q. Did Staff, like RUCO, request information about severance pay in the Company's last rate case?

A. Yes.

Q. What was the Company response to Staff data request 4.11 in the last rate case?

A. "The severance was paid in the ordinary course of business. Individual severance agreements contain confidentiality agreements that would preclude us from providing positions of such employees and the details of the circumstances resulting in the severance payment without their consent. **Although the Company cannot identify each employee individually or on a position basis, the severance payments are generally made to employees at the middle management or professional level or higher, and is consistent with requests made in prior rate cases."** [emphasis added]

Q. Did RUCO ask the Company a follow-up data request in this case regarding a less invasive question about the severance package(s) and the "*general circumstances surrounding the severance package(s)*" which the Company seeks to recover from ratepayers?

A. Yes. RUCO in data request 4.07(f) was seeking the general nature of the separation if it was due to a firing, layoff, resignation, retirement, or other. RUCO asked the following in data:

f. What percentage of severance pay expense was related to each of the following categories:
i. Firing
ii. Layoff's
iii. Resignations
iv. Retirements

Q. What was the Company's response?

A. "The Company objects to this request as "Firing", "Layoffs", "Resignations" and "Retirements" are undefined terms and are vague and ambiguous. Without waiver of objection the Company states as follows:

i. Undetermined as the term "Firing" requires a contextual definition.

ii. None

iii. None

iv. None"

Q. Does RUCO believe these terms are straightforward and have other regulated utility companies in Arizona been able to answer these questions?

A. Yes. For example Southwest Gas was able to answer this data request.

Q. Does RUCO believe this information is relevant in making its determination on whether an adjustment needs to be made?

A. Yes. For example, if the Company offers an early retirement severance package to encourage employees to retire early and can show it will benefit ratepayers through a cost benefit analysis in the long run, then RUCO would ***not*** make an adjustment.

Q. What did the Commission decide in regards to severance pay in the Company's last rate case Decision No. 77856 (dated December 31, 2020)?

A. The Commission stated:

> "TEP asserts that it was not able to provide information regarding severance because of legal restrictions and confidentiality concerns. However, RUCO is a party to the confidentiality agreement with TEP. The Company could have provided redacted information to RUCO to support its Severance Pay Expense, but did not.
>
> Thus, we find that RUCO's recommendation that the Commission reject TEP's Severance Pay Expense is reasonable and we adopt it."[28]

---

[28] See page, 87 line 6 of Decision No. 77856.

Q. Does RUCO believe ratepayers should pay extra compensation to middle management or higher-level management when they separate from the Company?

A. No, this is a cost that should be borne solely by the shareholders. In addition, if the Company will not answer simple straight forward, unambiguous questions which ask simply for the Company to provide support for their request, ratepayers should not have to reimburse the Company for the expense. The Company enters into severance package agreements and is responsible for the terms – if the Company enters agreements knowing that the agreements will prevent disclosure of details necessary to support its requests to recover the cost from ratepayers, the Company should not request recovery and the Commission should not award unsupported recompense from ratepayers. The Commission, not the Company, determines what is recoverable from ratepayers and the Company, not RUCO or Staff, has the burden of supporting its requests.

Q. Are there any new arguments in this rate case that the Company has set forth?

A. No. The Company made the same or similar arguments that were recently rejected by the Commission in the Company's last rate case.

Q. What is RUCO's recommendation?

A. RUCO recommends the removal of $907,395 in severance pay, as shown in RUCO Schedule 21.

Operating Income Adjustment No. 8 – Industry and Membership Dues

Q. Has the Company asked for ratepayers to pay for industry and membership dues in this rate case?

A. Yes.

Q. Please briefly describe some of the industry groups that the Company subscribes to.

A. The Company pays membership dues to the following organizations:

Baker Botts LLP – Baker Botts LLP is made up of environmental coalitions that equip their members with effective tools in advocacy, as well as avenues to track new legislation, regulatory initiatives and litigation trends. The class of 85 is an ad hoc coalition of electric generating companies located throughout the United States that focuses on air and climate issues affecting the industry. CCIG focuses primarily on water, wildlife and waste issues affecting the power sector. CCIG members are located throughout the country and own and operate a diverse portfolio on generating assets. TEP's total dues for Baker Botts LLP during the test year (ending December 31, 2021) were $73,350.

Western Energy Supply and Transmission ("WEST") Associates – WEST Associates is a coalition of 10 cooperatives, public power and investor-owned electric utilities serving over 12 million customers in 11 Western states. WEST Associates advocates on behalf of the member utilities to ensure that uniquely western issues impacting member companies and their operations are recognized in federal, state and local regulatory proceedings. TEP's total dues for WEST Associates during the test year (ending December 31, 2021) were $27,246.

Edison Electric Institute ("EEI") – EEI is an association of U.S. shareholder-owned electric companies. Organized in 1933, EEI works closely with all of its members, representing their interests and advocating equitable policies in legislative and regulatory arenas. Total dues for EEI during the test year (ending December 31, 2021) were $636,169.

Utility Solid Waste Activities Group ("USWAG") – Total dues paid to EEI for USWAG during the test year (ending December 31, 2021) were $34,428. The USWAG membership costs are charged as follows: 90% to TEP and_10% to UNS Electric Inc. TEP's portion of total dues during the test year (ending December 31, 2021) were $30,985.

Electric Power Research Institute ("EPRI") – The Electric Power Research Institute, Inc. conducts research, development and demonstration (RD&D) relating to the generation, delivery and use of electricity for the benefit of the public. An independent, nonprofit organization that brings together scientists and engineers as well as experts from academia and the industry to help address challenges in the electric industry. EPRI's work spans nearly every area of electricity generation, delivery and use, management and environmental responsibility. EPRI provides both short- and long-term solutions in these research areas for the electricity industry, its customers and society. TEP's total dues for EPRI during the test year (ending December 31, 2021) were $678,547. No portion of the dues relates to lobbying activities.

Q. Whose interest do these groups represent?

A. These groups represent the interest of electric generators such as UNS and TEP, donations and membership is purely voluntary, many of which are political in nature, and may not be necessary for the provision of utility services.

Q. Has the Company already removed lobbying expenses from these industry organizations?

A. Yes, as they are easily identified and cannot be deducted for tax purposes. In addition, those organizations must identify any lobbying activities.

Q. What is the amount of lobbying expense the Company has removed?

A. $109,113.

Q. What has the Commission decided in prior rate cases?

A. The Commission reduced EEI dues by 49.93 percent in Decision Nos. 71914 and 70860.

Q. How was this percentage determined in those Decisions?

A. The percentage was determined using the following NARUC Operating Expense Categories:[29]

NARUC Operating Expense Categories	Percentage of Dues
Legislative Advocacy	20.38%
Regulatory Advocacy	16.49%
Advertising	1.67%
Marketing	3.68%
Public Relations	7.71%
Total Expenses	49.93%

Q. Has RUCO updated this information from EEI?

A. Unfortunately, RUCO cannot. After 2006, the EEI stopped providing this information.

Q. So, in other words, the letter the Company received from EEI only addresses one expense category - Lobbying activity?

A. Yes. The letter provides no information on the other eight expense categories. It only makes sense that most of these costs have been shifted elsewhere, but RUCO does not know where because EEI does not supply an expense report anymore that has these details.

[29] Based on the Edison Electric Institute Schedule of Expenses by NARUC Category For Core Dues Activities for the Year Ended December 31, 2005.

Q. What did the Commission decide in Commission Decision No. 77856 (dated December 31, 2020) TEP's last rate case.

A. "We agree with RUCO that these memberships serve the interests of electric generators and should be partially disallowed. While the disallowances by Staff and RUCO do not perfectly align, the $502.000 downward adjustment made by TEP exceeds the proposed disallowance by either Staff or RUCO. Accordingly, we find that TEP's proposed adjusted Membership Dues Expense is reasonable and we adopt it."[30]

Q. Would RUCO like to provide any additional information in this rate case regarding Industry Dues?

A. Yes, more recently in Commission Decision No. 78317 (dated November 9, 2021) the Commission stated:

> *"APS has removed from its request significant portions of association dues that are attributable to legislative and regulatory advocacy, specifically for EEl. We have previously disallowed portions of EEl dues attributable to legislative and regulatory advocacy, advertising, marketing, and public relations. (Decision No. 71914 at 25, Decision No. 70360 at 26.) We do not believe that APS has removed from its requested association dues expense all advocacy-related expenses (for example, AriSEIA engages in advocacy activities). However, by removing the EEl dues attributable to advocacy efforts, APS has acted in keeping with our prior decisions on this issue. APS has relied upon various associations in the past to remain current concerning developments in the energy industry and to support and obtain access to current research and other information that it otherwise may not be able to readily obtain, and such knowledge gained also benefits APS's shareholder.* ***Therefore, consistent with RUCO's position, we conclude that it is just and reasonable to allow recovery of only 50% of the $3.582 million (i.e., $1.791 million) in association dues requested****."*[31]

[30] See page, 79 line 1 of Decision No. 77856.

[31] See page, 196 line 18 of Decision No. 78317.

Q. What is RUCO's recommendation?

A. RUCO recommends a disallowance of 50 percent of Industry dues, in the amount of $607,375, as shown in RUCO Schedule 22.

RUCO's recommendation is the same as in the last rate case; that in the future it is incumbent on the Company to provide all the expense categories to support its EEI dues categories. Further, the Commission should send a strong message to the Company that all EEI dues may be disallowed in the future if this information is not provided.

Operating Income Adjustment No. 9 – Other Membership Dues

Q. Has the Company asked Ratepayers to pay for other Membership Dues?

A. Yes.

Q. Has RUCO reviewed the Company's request?

A. Yes.

Q. What is RUCO's recommendation?

A. [BEGIN CONFIDENTIAL] [redacted]

[redacted] [END CONFIDENTIAL]

RUCO recommends a disallowance of 100 percent of these dues or $96,986, as shown in RUCO Schedule 23.

Operating Income Adjustment No. 10 – Depreciation Expense

Q. Is another RUCO witness covering rate case expense?

A. Yes. RUCO witness Ms. Crystal Brown will be providing testimony on RUCO's recommended depreciation expense, as shown in RUCO Schedule 24.

Operating Income Adjustment No. 11 – Rate Case Expense

Q. Is another RUCO witness covering rate case expense?

A. Yes. RUCO witness Mr. Bentley Erdwurm will be providing testimony on RUCO's recommended rate case expense, as shown in RUCO Schedule 25.

Operating Income Adjustment No. 12 – Interest Synchronization

Q. Please explain interest synchronization.

A. An interest synchronization adjustment is performed to ensure that the revenue requirement reflects the tax savings generated by the interest component of the revenue requirement. The interest synchronization expense is calculated by multiplying the rate base by the weighted average cost of debt. The combined state and federal income tax rates are then applied to the resulting interest deduction difference to determine the income tax expense adjustment.

Q. Has RUCO made an adjustment for interest synchronization?

A. Yes. Since the Company's rate base differs from RUCO's recommended rate base, an adjustment was required. RUCO's adjustment increases interest synchronization by $515,731, as shown in RUCO Schedule 26.

Operating Income Adjustment No. 13 – Income Tax Expense

Q. Has RUCO adjusted income taxes, as a result of its adjustments, mentioned above?

A. Yes. RUCO applied the statutory state and federal income tax rates to RUCO's taxable income. As a result, RUCO has increased income tax expenses for the adjusted test year by $12,102,232 as shown in RUCO Schedule 27.

Q. Does your silence on any issue in this rate filing preclude you from addressing these issues in future testimony?

A. No, it does not.

Q. Does this conclude your direct testimony?

A. Yes.

ATTACHMENT A

TEP's Responses to Company Uniform Data Requests and RUCO's Data Requests

UDR ECB-1.013

Incentive Programs. List and describe all retirement and incentive programs available to Company officers and employees. Provide a complete copy of each incentive compensation program and all related materials. Identify the goals and targets in each year 2019-2021, and all evaluations of whether such goals were exceeded. State the cost by program, of each retirement program directly charged or allocated.

RESPONSE:

THE FILES LISTED BELOW CONTAIN CONFIDENTIAL INFORMATION AND ARE BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT.

Incentives:

All TEP non-union employees participate in UNS's short-term incentive program ("PEP"), which is tied to annual compensation.

The PEP performance targets and weighting are based on factors that are essential for the long-term success of the Company and are identical to the performance objectives used in its performance plan for other non-union employees. In 2021, the objectives were (i) Efficient Growth; (ii) Valued Customers; (iii) Thriving Employees; and (iv) Social Impact, which include both quantitative and qualitative measures. The Compensation Committee of the Board of Directors selected the goals and individual weightings for the 2021 PEP to ensure an appropriate focus on profitable growth and expense control, as well as operational and customer service excellence, safety and inclusivity for employees, and sustainability. This balanced scorecard approach encourages all employees to work toward common goals that are in the interests of UNS's various stakeholders. The outcomes of these efforts all benefit our customers in the long run.

The financial and other metrics for the Company's 2021 Short-Term Incentive Compensation program were:

- Efficient Growth – 40%
  - Net Income – 30%
  - Cash Flow from Operations – 10%
- Valued Customers – 25%
  - System Average Interruption Duration Index (SAIDI) – 10%
  - Performance on JD Power Survey – 10%
  - O&M – 2021 Actuals vs. Target – 5%
- Thriving Employees – 25%
  - Safety Report Responses – 10%
  - Total Recordable Incident Rate – 5%
  - Diversity, Equity & Inclusion (DEI) – 10%
- Social Impact – 10%
  - Sustainability – 10%

In developing the PEP performance targets, Company management compiles relevant data such as Company historic performance and industry benchmarks and makes recommendations to the

Compensation Committee for a particular year, but the Compensation Committee ultimately determines the performance objectives that are adopted.

The scores from each goal are totaled and then multiplied by the targeted bonus of each employee to determine the total available dollars to be paid out. Targeted bonus percentages, as a percent of base salary, range from 9% - 12% for unclassified employees, and 20-25% for senior management level employees. Bonus percentages, as a percent of base salary, are used in the calculation of total available dollars, and actual awards may vary at management's discretion based on individual employee contribution. If a payout is achieved, employee PEP bonuses will be distributed near the end of the first quarter the following year. Please see the files listed below for the goals for each year and evaluations of yearly performance.

File Name	Bates Numbers
UDR ECB-1.013 2019 PEP Goals-Confidential.pdf	TEP\002270-002271
UDR ECB-1.013 2020 PEP Goals-Confidential.pdf	TEP\002272-002273
UDR ECB-1.013 2021 PEP Goals-Confidential.pdf	TEP\002274-002275

Retirement Programs:

TEP employees are eligible to participate in one of the pension plans for employees of TEP. Please see the file listed below for the summary plan description.

File Name	Bates Numbers
UDR ECB-1.013 TEP_Hourly_Plan_SPD-CONFIDENTIAL.pdf	TEP\002276-002303
UDR ECB-1.013 TEP_Salary_Plan_SPD-CONFIDENTIAL.pdf	TEP\002304-002331

Additionally, TEP employees are eligible to participate in the TEP 401(k) Plan as described below:

401(k) Plan

All employees participate in the TEP's 401(k) Plan, which takes advantage of Section 401(k) of the Internal Revenue Code and permits employees to voluntarily save from 1/2% to 25% of their pay, before any deduction for state or federal income taxes. The Company matches dollar on dollar, up to 4.5% of pay saved in the 401(k) Plan for TEP employees.

Employees' savings and Company matching contributions are invested in one or any combination of a selection of professionally managed investment funds at the direction of the employee. Employees are eligible to join the 401(k) Plan upon their date of employment. Company matching fcontributions are fully and immediately vested. Please see the file listed below for the summary plan description.

File Name	Bates Numbers
UDR ECB-1.013 401K_SPD-CONFIDENTIAL.pdf	TEP\002236-002269

Retirement program expense directly charged or allocated to TEP during each year was as follows:

	2019	2020	2021
TEP SERP Plan (FERC 0926)	$1,220,988	$1,517,589	$1,688,728
TEP Union and Salaried Pension Plans (FERC 0926)	6,285,584	2,729,319	-910,855
TEP 401K Plan (FERC 0926)	3,673,268	3,751,859	4,158,738
UNS Electric Pension/401K (FERC 0926)	44,387	54,675	55,715
UNS Gas Pension/401K (FERC 0926)	19,653	19,072	18,312
Deferred Compensation Plan (FERC 0920)	(482,565)	(456,535)	(578,305)
Total	$10,761,315	$7,615,979	$4,432,333

RESPONDENT:

Kris Page-Iverson/Mark Stankevitz

WITNESS:

Brian Brumfield

UDR ECB-1.014

Payroll, Incentive Programs.

a. Please describe bonus programs or incentive award programs in effect at the Company for the most recent three years.

b. Identify incentive and bonus program expense incurred in 2019-2021. Identify the accounts charged.

c. Identify all incentive and bonus program expense charged or allocated to the Company from affiliates in 2019-2021.

RESPONSE:

a. **THE FILE LISTED BELOW CONTAINS CONFIDENTIAL INFORMATION AND IS BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT.**

Please see TEP's response to UDR ECB-1.013 for the description of the short term incentive program available to TEP's non-union employees related to their annual compensation. Union employees are not eligible for the short term incentive program – their annual compensation is not based in part on performance incentives as is the case with non-Union employees.

Long-term Incentive Program:

TEP states that the officers of UNS who provide services to TEP are eligible to participate in a long-term incentive program. For a description of the program, please see:

UDR ECB 1.014 2019 LTI Program Term Sheet_Confidential.pdf, Bates Nos. TEP\002332-002335

UDR ECB 1.014_2020 LTI Program Term Sheet_Confidential.pdf, Bates Nos. TEP\002336-002339

UDR ECB 1.014_2021 LTI Program Term Sheet_Confidential.pdf, Bates Nos. TEP\002340-002343

b.-c. Please see UDR ECB-1.014 TEP Incentive Comp and Bonus Summary Info Confidential.xls for both short-term and long-term incentive program expense directly charged or allocated to TEP in 2019 through 2021 and the corresponding accounts charged. The Excel file is not identified by Bates number.

RESPONDENT:

Gabrielle Camacho (a) and Mark Stankevitz (b and c)

WITNESS:

Brian Brumfield

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO UNIFORM DATA REQUESTS – 2022 TUCSON ELECTRIC POWER RATE CASE DOCKET NO. E-01933A-22-0107 June 24, 2022

UDR IER-1.016

Accounting Adjustments.

a. Please identify any aspects of the Company's accounting adjustments and revenue requirement claim that represent a conscious deviation from the principles and policies established in prior Commission Orders.

b. Identify each area of deviation, and for each deviation explain the Company's perception of the principle established in the prior Commission Orders, and the dollar impact resulting from such deviation.

c. Show which accounts are affected and the dollar impact on each account for each such deviation.

RESPONSE:

a-b. Listed below are the Company's accounting adjustments and revenue requirement claim that represent a conscious deviation from rulings with respect to TEP in prior Commission Orders:

1) Pension Adjustment – The Pension Adjustment was prepared and calculated in the same manner as approved by the Commission in the last TEP rate case with the exception of including the current cost of the Supplemental Executive Retirement Plan ('SERP") for the Company's executives. Although the Company's request for recovery of SERP cost in the last rate case was disallowed, SERP costs should be included in the revenue requirement as supported in the direct testimony of Mr. Brumfield.

2) Short-Term Incentive Compensation – The Company's short-term incentive compensation plan is called the Performance Enhancement Plan ("PEP"). In the prior rate case, the Commission granted recovery of 60% of PEP, however, the Company believes it is appropriate to recover 100% of PEP, as supported in the direct testimony of Mr. Brian Brumfield.

3) Long-Term Incentive Compensation – The current rate case includes a Long-Term Incentive Compensation (LTI) adjustment to produce a pro forma Test Year expense level reflecting the average level of LTI expense. In the prior rate case, TEP did not receive recovery of this cost, but the Company believes it is appropriate to recover LTI, as supported in the direct testimony of Mr. Brumfield.

c. Please see UDR IER-1.016c Worksheet.xlsx. The Excel file is <u>not</u> identified by Bates numbers.

RESPONDENT:

Rigo Ramirez

WITNESS:

Jason Rademacher

Tucson Electric Power Company
UDR 1.016c
Test Year Ended 2021

	FERC Acct		Total Company	ACC %		ACC Jurisdictional
Pension Adjustment (SERP)	0926	$	1,688,728	86.44%	$	1,459,808
Short-Term Incentive Compensation (PEP)	0408	$	283,380	86.44%	$	244,953
	0500		66,666	90.22%		60,146
	0506		708,896	90.22%		639,566
	0514		298,763	90.22%		269,544
	0566		279,626	9.09%		25,421
	0570		40,906	9.09%		3,719
	0588		337,309	100.00%		337,309
	0598		56,967	100.00%		56,967
	0903		179,261	100.00%		179,261
	0920		2,321,229	86.44%		2,006,470
		$	4,573,003		$	3,823,356
Long-Term Incentive Compensation	0920	$	3,164,190	86.44%	$	2,735,258
Total Impact		$	9,425,922		$	8,018,422

UDR ECB-1.020

Severance Pay Expenses. State whether the test year ending December 31, 2021 includes any amounts for severance pay. If yes, provide the amount included in the adjusted test year and identify the account charged.

RESPONSE:

The test year includes severance pay of $907,395 (all O&M); $869,618 was recorded in FERC Account 920 and $37,777 in FERC Account 408.1.

RESPONDENT:

Paige Bennetts

WITNESS:

Brian Brumfield

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO's 1st SET OF DATA REQUESTS – 2022 TUCSON ELECTRIC POWER RATE CASE DOCKET NO. E-01933A-22-0107
August 29, 2022

RUCO 1.46

Board of Directors Fees – Please answer the following questions as they relate to Board of Directors Fees:

a. The names of the board of directors.
b. The amount broken down by base salary, stock compensation, or other compensation.
c. The amount the Company is seeking recovery of from ratepayers on both a Company-wide basis and on an Arizona jurisdictional basis.
d. The FERC account number(s) that the Company records the board compensation in.

If any of the Board of Directors are also NEOs, and if they are receiving compensation both as NEOs and Board Members.

RESPONSE:

a. The names of the UNS Energy Board of Directors as of December 31, 2021 are listed below:

Last	First Name
Duke	Nora
Elliott	Robert
Francesconi	Louise
Gray	Susan
Kehaly	Pamela
Lovallo	Lisa
Perry	Jocelyn
Peru	Ramiro
Pivirotto	Gregory
Reid	James
Ruiz	Joaquin

b. Compensation to the Board of Directors (for all directors combined) is comprised of flat retainers of which $824,009 was charged to TEP during the test year.
c. TEP seeks to recover $712,273 of the amount listed in part b from ACC jurisdictional retail ratepayers in Arizona.
d. Board of Directors compensation is charged to FERC account 930.2.
Members of the Board of Directors who are also executive officers do not receive any incremental compensation related to their membership on the Board of Directors.

RESPONDENT:

Georgia Hale

WITNESS:

Brian Brumfield

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO's 4th SET OF DATA REQUESTS – 2022 TUCSON ELECTRIC POWER RATE CASE DOCKET NO. E-01933A-22-0107 November 14 , 2022

RUCO 4.02

Director and Insurance Expense (D&O) – Please answer the following questions as they relate to D&O expenses:

a. The total amount of D&O expense incurred by Fortis the parent company in the test-year.

b. The total amount allocated to Arizona and the amount allocated to TEP in the test-year.

c. If Fortis did not allocate D&O expenses in a. The amount of savings that ratepayers in Arizona received (e.g., 80 percent of D&O expenses that were not allocated to Arizona from Fortis).

d. The amount of D&O expense TEP would have to incurred in the test-year on a standalone basis.

e. Provide the D&O expense on a calendar year basis for the last 10 years, that was allocated to TEP.

RESPONSE:

THE FILES LISTED BELOW CONTAIN CONFIDENTIAL INFORMATION AND ARE BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT.

a. The Company objects to this request as irrelevant. D&O expense incurred by Fortis for its directors and officers is charged to TEP through the Fortis management fee. TEP is not seeking recovery of Fortis management fees in this rate case.

b. The Company objects to this request as irrelevant. D&O expense incurred by Fortis for its directors and officers is charged to TEP through the Fortis management fee. TEP is not seeking recovery of Fortis management fees in this rate case.

c. The Company objects to this request as irrelevant. D&O expense incurred by Fortis for its directors and officers is charged to TEP through the Fortis management fee. TEP is not seeking recovery of Fortis management fees in this rate case.

d.

File Name	Bates numbers
RUCO 4.02 Confidential.pdf	TEP\013932-013933

e.

File Name	Bates numbers
RUCO 4.02 Confidential.pdf	TEP\013932-013933

RESPONDENT:

Mark Stankevitz/Georgia Hale

WITNESS:

Jason Rademacher

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO
RUCO's 4th SET OF DATA REQUESTS –
2022 TUCSON ELECTRIC POWER RATE CASE
DOCKET NO. E-01933A-22-0107
November 14 , 2022

RUCO 4.06

Board of Directors Fees – This is a follow-up to RUCO data request 1.46, please answer the following questions as they relate to Board of Directors Fees. Provide the number of shares each board member owns in Fortis Inc.

RESPONSE:

The Company objects to the question as irrelevant. However, without waiver of objection, to the Company's knowledge current UNS Energy Corporation Directors James Reid, Jocelyn Perry and Gary Smith own Fortis stock, the amounts of which are reported and available in Fortis' publicly filed reports. UNS Director Susan Gray also owns Fortis stock the specific number of which is not publicly available. The Company does not have information on whether the remaining directors own Fortis stock since ownership is not required nor a component of their compensation.

RESPONDENT:

Legal Services

RUCO 4.07

Severance Pay – This is a follow-up to UDR ECB 1.020, please answer the following. questions as they relate to severance pay.

a. Are union employees and employees of the Company's wholly owned subsidiaries eligible for severance pay, or any other employee who does not work directly for the Company? If so, please list the number of employees who do not work directly for the Company that have received severance pay and the amount paid-out by annualized test year for the prior five years?

b. Provide the total severance pay amounts paid-out by annualized test year for the prior five years for employees who work directly for the Company. In addition, please include the amount on a Company-wide basis and the amount that has been allocated to Arizona.

c. Is recovery of severance pay requested in all the Company's rate cases? If not, please explain?

d. Please provide the categories that would be included in the individual's severance pay package (i.e., stock options, medical benefits, etc.).

e. Is any severance pay expense based on Company financials or other performance measures? If so, please explain.

f. What percentage of severance pay expense was related to each of the following categories:

   i. Firing

   ii. Layoff's

   iii. Resignations

   iv. Retirements

g. Provide a blank copy of the Company's severance pay contact.

RESPONSE:

THE FILES LISTED BELOW CONTAIN CONFIDENTIAL INFORMATION AND ARE BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT.

a. Unclassified employees are eligible for severance pay pursuant to the Company's severance plan so long as certain conditions set forth in the plan are met. The terms and conditions applicable to classified employment are set forth in the applicable Collective Bargaining Agreements and subject to negotiation. The Company has no wholly owned subsidiaries with employees.

b.

Year	Company-wide	ACC Jurisdictional Allocation
2020	$580,828	$507,525
2019	$157,313	$147,564
2018	$549,903	$455,547
2017	$1,350,200	$1,167,924
2016	$512,764	$447,380

c. Yes.

d. Per the severance plan, severance agreements may include wages and a subsidy for COBRA health insurance coverage.

e. No.

f. The Company objects to these this request as "Firing", "Layoff's", "Resignations" and "Retirements" are undefined terms and are vague and ambiguous. Without waiver of objection the Company states as follows:

i. Undetermined as the term "Firing" requires a contextual definition.

ii. None

iii. None

iv. None

g. The Company objects to this request as the Company's severance pay contracts are irrelevant, not uniform and are individually negotiated. Without waiver of objection, please see:

File Name	Bates Numbers
RUCO 4.07-UNS Severance Pay Plan-Confidential.pdf	TEP\014099-014119
RUCO 4.07-First Amendment to the Severance Pay Plan (2012)-Confidential	TEP\014062-014067
RUCO 4.07-Second Amendment to the Severance Pay Plan (2013)-Confidential	TEP\014068-014070
RUCO 4.07-SPD - UNS Energy Corporation Severance Pay Plan (Officers) (2013)-Confidential.pdf	TEP\014085-014098

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO
RUCO's 4th SET OF DATA REQUESTS –
2022 TUCSON ELECTRIC POWER RATE CASE
DOCKET NO. E-01933A-22-0107
November 14 , 2022

File Name	Bates Numbers
RUCO 4.07-SPD - UNS Energy Corporation Severance Pay Plan (Employees) (2013)-Confidential.pdf	TEP\014071-014084

RESPONDENT:

Anna Ritchie

WITNESS:

Jason Rademacher

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO's 6th SET OF DATA REQUESTS – 2022 TUCSON ELECTRIC POWER RATE CASE DOCKET NO. E-01933A-22-0107 November 25, 2022

RUCO 6.01

Short-Term Incentive Pay – Please reconcile the amounts given in the Company's Income – Short-Term Incentive excel worksheet (Pro-forma adjustment) to the amounts provided in Company Uniform Data Request ("UDR") 1.016c by FERC account number. For example, under the Performance Enhancement Plan ("PEP"), Company UDR 1.016c shows the total amount of PEP in FERC account 0500 on a company-wide basis to be $66,666 and on a jurisdictional basis to be $60,146, but on the Company's excel pro-forma adjustment the amount for the test-year PEP is $222,960. If possible, start with the amounts from UDR 1.016c and reconcile to the amounts in the Company's pro-forma excel sheet. (See Attachment)

RESPONSE:

Please see RUCO 6.01 Short-Term Incentive Compensation Reconciliation.xlsm for the short-term incentive compensation reconciliation.

The Excel file is not identified by bates numbers.

RESPONDENT:

Mark Stankevitz

WITNESS:

Jason Rademacher

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO's 6th SET OF DATA REQUESTS – 2022 TUCSON ELECTRIC POWER RATE CASE DOCKET NO. E-01933A-22-0107 November 25, 2022

RUCO 6.02

Long-Term Incentive Pay – Please reconcile the amount given in the Company's Income – Long-Term Incentive excel worksheet (Pro-forma adjustment) to the amount provided in Company UDR 1.016c by FERC account number. For example, UDR 1.016c shows Long-Term Incentive Compensation on a company-wide basis to be $3,164,190 and on a jurisdictional basis to be $2,735,258, but on the Company's excel pro-forma adjustment the amount for the test-year Long-Term Incentive is $3,075,005. (See Attachment)

RESPONSE:

The pre-jurisdictional amount shown in the UDR of $3,164,190 represents the 3-year average of long-term incentive compensation expense recorded in FERC 920 for the years ended December 31, 2019 ($3,423,953), 2020 ($2,993,611) and Test Year 2021 (3,075,005).

RESPONDENT:

Mark Stankevitz

WITNESS:

Jason Rademacher

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO's 6th SET OF DATA REQUESTS – 2022 TUCSON ELECTRIC POWER RATE CASE DOCKET NO. E-01933A-22-0107 November 25, 2022

RUCO 6.03

Supplemental Executive Retirement Plant ("SERP") – Please reconcile the SERP amount given in Company UDR 1.016c to the amount provided in the Company's Income – Pension excel worksheet (Pro-forma Adjustment), tab 4 Fortis Actuary Report. (See Attachment)

RESPONSE:

The difference between the TEP SERP amount of $1,990,486 per actuary report and the pre-jurisdictional amount of $1,688,728 per UDR is due to allocations to UNS Gas and UNS Electric.

RESPONDENT:

Mark Stankevitz

WITNESS:

Jason Rademacher

RUCO 6.04

Short-Term Incentive Pay Pro-Forma Excel worksheet – Please answer the following questions as they relate to the Company's Pro-forma Excel worksheet:

a. Does the test year amount include the 2021 bonuses? For example, FERC account 506 does this account include only the amount paid for PEP of $1,602,127 or does it also include the 2021 wage increase of 2.53 percent and the 2022 wage increase of 3.47 percent?

b. Please explain the 2018 and 2019 true-ups on excel tab 2 Stl Pivot Tbl.

RESPONSE:

a. Yes, the test year amount includes the 2021 bonuses with the 2021 wage increase built in; it does not include the 2022 wage increase.

b. Each year TEP records estimated short-term incentive compensation expense for the current year that is trued-up to actual in the following year upon payout. Thus, the 2018 true-up represents the true-up of 2018 estimated short-term incentive compensation expense to actual in 2019 and the 2019 true-up represents the true-up of 2019 estimated short-term incentive compensation expense to actual in 2020.

RESPONDENT:

Mark Stankevitz

WITNESS:

Jason Rademacher

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO's 6th SET OF DATA REQUESTS – 2022 TUCSON ELECTRIC POWER RATE CASE DOCKET NO. E-01933A-22-0107 November 25, 2022

RUCO 6.05

Incentive/Pension Plans (PEP, Long-Term, SERP) – Does the Company benchmark against other Utilities Companies? If so, please provide those benchmarking surveys/studies (e.g., Salary studies conducted by Korn Ferry).

RESPONSE:

A competitive assessment of incentive compensation programs relative to market practice was conducted in 2021. The review found that overall incentive program design is within the range of peer and broad market practice and aligns with many aspects of compensation "best practice."

Due to the confidential and high employee sensitivity of the incentive compensation study, it will not be forwarded to the parties. However, the Company is willing to make the study available for RUCO to review at TEP's corporate headquarters in Tucson or at its law firm in Phoenix under the terms of the Protective Agreement in this matter. Please let TEP know if you would like to setup an appointment to review the study in Tucson or Phoenix. At such time, a TEP Human Resources Department representative will be available to meet with RUCO's representative to explain the study or to answer specific questions about the study.

RESPONDENT:

Kris Page-Iverson

WITNESS:

Jason Rademacher

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO's 6th SET OF DATA REQUESTS – 2022 TUCSON ELECTRIC POWER RATE CASE DOCKET NO. E-01933A-22-0107 November 25, 2022

RUCO 6.06

TEP – Auto Pay – Please answer the following questions as they relate to TEP – Auto Pay:

a. For customers who elect to pay their bills through TEP - Auto Pay how much does this cost the customer?

b. For customers who elect to pay their bills through TEP – Auto Pay how much does it cost the Company?

c. Does the Company charge the customer a monthly fee or transaction fee for using TEP – Auto Pay?

d. As a general proposition does TEP – Auto Pay assist the Company by assuring the collection of customers' bills in a timely and efficient manner without late fees? If No, please explain.

e. How much did the TEP – Auto Pay save TEP in the test-year and five prior years, as opposed to the standard mailing in of customer checks and processing them?

RESPONSE:

a. Auto Pay is a free payment option that allows a customer to have their bill automatically paid by/deducted from the customer's checking or savings account.

b. The Company pays a $0.04 bank fee per Auto Pay transaction, any applicable account validation fees, monthly minimum charges, web and system maintenance, and depreciation or amortization of assets.

c. The Company does not charge the customer any monthly or transaction fees.

d. Auto Pay is a customer choice and convenience payment offering that helps them avoid paying for postage or one-time transaction fees from a third party. Customers must choose to enroll in this payment option as the Company does not automatically enroll anyone on Auto Pay. We believe customers enrolled in Auto Pay are customers who choose to pay timely regardless of payment option.

e. We do not have this information. We view this as a convenience option for our customers – if there are any savings related to this program, it would be reflected in our ongoing operations and maintenance expense.

RESPONDENT:

Aaron Groff

WITNESS:

Lynne Petersen

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO's 6th SET OF DATA REQUESTS – 2022 TUCSON ELECTRIC POWER RATE CASE DOCKET NO. E-01933A-22-0107 November 25, 2022

RUCO 6.07

Arizona Trail Association –_The Company states the following about the Arizona Trail Association:

> *"Through our TEP Gives program, when you sign up for Budget Billing, e-bill or Auto Pay, we'll make a donation to the Arizona Trail Association.*
>
> *Our contributions are funded with company resources, not with customers' rates. TEP is committed to community improvement and engagement. When all of us work together, we can be good stewards of the land and promote opportunities to connect with nature."*

Please answer the following questions about the Arizona Trail Association:

a. Are there other entities, groups, or associations that ratepayers can have TEP donate to?

b. How much does TEP donate to Arizona Trail Association per customer transaction when a customer signs up for Budget Billing, e-bill or Auto Pay?

c. How much did TEP donate to the Arizona Trails Association in the test-year? And prior 5 years?

d. Why did TEP select the Arizona Trail Association as a recipient rather than some other charity?

e. In order to save processing costs on mailing and printing the bills, why didn't the Company just credit the ratepayers' bills as an incentive to help the Company reduce billing costs?

RESPONSE:

a. The TEP Gives program was a pilot program in 2021 that continued in 2022. In 2021 a different non-profit was chosen each quarter to be the beneficiary based on TEP's philanthropy focus. Q1 the beneficiary was the Food Bank of Southern Arizona, Q2 was The Nature Conservancy, Q3 was Junior Achievement, and Q4 was Arizona Children's Association. In 2022 the decision was made to have two beneficiaries for the year. The first half of 2022 the beneficiary was Emerge Center to End Domestic Violence, and the second half of the year is the Arizona Trail Association.

b. The average was $2 per customer with a cap of $20,000 per quarter.

c. TEP's donations to the Arizona Trail Association the past 6 years were:

2021 $20,000

2020 $ 8,870

2019 $10,000

2018 $10,000

2017 $10,125

2016 $ 5,000

d. The Arizona Trail Association is a collaboration partner in our environment/sustainability focus area. Although the funding is unrestricted for the TEP Gives program, in discussion with the Arizona Trail Association it was agreed that funding from the TEP Gives program would primarily support the Planting the Seeds of Stewardship program, a youth outreach, education and stewardship initiative. The mission of the Seeds of Stewardship program is to provide educational and meaningful outdoor experiences that empower income-qualified youth to become the next generation of stewards of Arizona's wild landscapes. They work with youth within Arizona Trail gateway communities using a proven three-tiered approach of experience, education, and service-learning. By engaging, inspiring, and empowering middle school and high school students, they help plant the seeds of environmental stewardship for future generations.

e. TEP's philanthropic donations come from shareholder funds, not customers. The TEP Gives program promotion was only conducted through social media and TEP's website.

RESPONDENT:

Wendy Erica Werden

WITNESS:

Lynne Petersen

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO's 6th SET OF DATA REQUESTS – 2022 TUCSON ELECTRIC POWER RATE CASE DOCKET NO. E-01933A-22-0107 November 25, 2022

RUCO 6.08

TEP e-bill – Please answer the following questions as they relate to TEP e-bill?

a. How much does the Company save per customer transaction in processing costs over the standard mail in option?

b. Provide the annual savings by using TEP e-bill over the standard mail option for the test-year and five prior years.

RESPONSE:

a. E-bill is a customer choice and convenience billing offering that provides electronic bills according to customer preference. Customers must choose to enroll in e-bill and can un-enroll at any time. The Company does not automatically enroll anyone. The average cost for printing and mailing a bill is \$0.64 compared to \$0.01 for e-bill. Any savings related to this program would be reflected in our ongoing operations and maintenance expense.

b. Savings would be limited to e-bill cost reductions or increases since the last approved rate case. E-bill cost is \$0.01 now and was \$0.01 in the last rate case. Enrolled e-bill customers increased an average of 12,000 per year. Annual savings was estimated at \$90,000. These savings are reflected in the test year data and help to fund the significant cost increase due to CNP regulations added after the last approved rate case.

RESPONDENT:

Aaron Groff

WITNESS:

Lynne Petersen

SCHEDULES

Tucson Electric Power
Docket No. E-01933A-22-0107
Test Year Ended December 31, 2021

TABLE OF CONTENTS TO RUCO'S DIRECT SCHEDULES

SCH. NO.	
RUCO-1	REVENUE REQUIREMENT ACC JURISDICTIONAL
RUCO-2	GROSS REVENUE CONVERSION FACTOR
RUCO-3	RATE BASE (OCRB, RCND, and FVRB) - ACC JURISDICTIONAL
RUCO-4	ORIGINAL COST RATE BASE - ACC JURISDICTIONAL
RUCO-5	SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS
RUCO-6	RECONSTRUCTION COST NEW LESS ACCUMULATED DEPRECIATION - ACC JURISDICTIONAL
RUCO-7	SUMMARY OF RECONSTRUCTION COST NEW LESS ACCUMULATED DEPRECIATION ADJUSTMENTS
RUCO-8	RATE BASE ADJUSTMENT NO. 1 - POST-TEST YEAR PLANT, ROUTINE PLANT
RUCO-9	RATE BASE ADJUSTMENT NO. 2 - POST-TEST YEAR PLANT RETIREMENTS
RUCO-10	RATE BASE ADJUSTMENT NO. 3 - ACCUMULATED DEPRECIATION
RUCO-11	RATE BASE ADJUSTMENT NO. 4 - CASH WORKING CAPITAL
RUCO-12	RATE BASE ADJUSTMENT NO. 5 - REGULATORY ASSETS & RELATED ADIT
RUCO-13	SUMMARY - OPERATING INCOME STATEMENT - ACC JURISDICTIONAL - ADJUSTED
RUCO-14	TEST YEAR AND RUCO RECOMMENDED ADJUSTMENTS
RUCO-15	OPERATING INCOME ADJUSTMENT NO. 1 - PAYROLL EXPENSE
RUCO-16	OPERATING INCOME ADJUSTMENT NO. 2 - REVERSE PAYMENT CARD PROCESSING FEES
RUCO-17	OPERATING INCOME ADJUSTMENT NO. 3 - BOARD OF DIRECTORS FEES
RUCO-18	OPERATING INCOME ADJUSTMENT NO. 4 - SHORT-TERM INCENTIVE PROGRAM
RUCO-19	OPERATING INCOME ADJUSTMENT NO. 5 - LONG-TERM INCENTIVE PROGRAM
RUCO-20	OPERATING INCOME ADJUSTMENT NO. 6 - SUPPLEMENTAL EXECTIVE RETIREMENT PLAN
RUCO-21	OPERATING INCOME ADJUSTMENT NO. 7 - SEVERANCE PAY
RUCO-22	OPERATING INCOME ADJUSTMENT NO. 8 - INDUSTRY MEMBERSHIP DUES
RUCO-23	OPERATING INCOME ADJUSTMENT NO. 9 - OTHER MEMBERSHIP DUES
RUCO-24	OPERATING INCOME ADJUSTMENT NO. 10 - DEPRECIATION EXPENSE
RUCO-25	OPERATING INCOME ADJUSTMENT NO. 11 - RATE CASE EXPENSE
RUCO-26	OPERATING INCOME ADJUSTMENT NO. 12 - INTEREST SYNCHRONIZATION
RUCO-27	OPERATING INCOME ADJUSTMENT NO. 13 - INCOME TAX EXPENSE

Tucson Electric Power
Docket No. E-01933A-22-0107
Test Year Ended December 31, 2021

RUCO Schedule 1
Witness: Michlik

REVENUE REQUIREMENT
ACC JURISDICTIONAL (Thousands of Dollars)

LINE NO.	DESCRIPTION	(A) COMPANY ORIGINAL COST	(B) COMPANY RCND	(C) COMPANY FAIR VALUE	(D) RUCO ORIGINAL COST	(E) RUCO RCND	(F) RUCO FAIR VALUE
1	Adjusted Rate Base	$ 3,625,148	$ 6,875,990	$ 5,250,569	$ 3,502,489	$ 6,642,627	$ 5,072,558
2							
3	Adjusted Operating Income (Loss)	100,884	100,884	100,884	136,847	136,847	136,847
4							
5	Current Rate Of Return (Line 3 / Line 1)	2.78%	1.47%	1.92%	3.91%	2.06%	2.70%
6							
7	Required Operating Income (Line 13 X Line 1)	$ 275,843	$ 275,843	$ 275,844	$ 236,068	$ 236,068	$ 236,068
8							
9	Weighted Average Cost of Capital (WACC)	7.31%	7.31%	7.31%	6.74%	6.74%	6.74%
10							
11	Adjustment to WACC	0.30%	-3.30%	-2.06%	0.00%	-3.19%	-2.09%
12							
13	Required Rate of Return	7.61%	4.01%	5.25%	6.74%	3.55%	4.65%
14							
15	Operating Income Deficiency (Line 7 - Line 3)	$ 174,959	$ 174,959	$ 174,960	99,220	99,220	99,220
16							
17	Gross Revenue Conversion Factor (Schedule JMM-2)	1.3381	1.3381	1.3381	1.3381	1.3381	1.3381
18							
19	Increase In Gross Revenue Requirement (Line 15 X Line 17)	$ 234,111	$ 234,111	$ 234,111	$ 132,766	$ 132,766	$ 132,766
20							
21	Adjusted Test Year Revenue	$ 1,096,192	$ 1,096,192	$ 1,096,192	$ 1,096,192	$ 1,096,192	$ 1,096,192
22							
23	Proposed Annual Revenue Requirement (Line 19 + Line 21)	$ 1,330,303	$ 1,330,303	$ 1,330,303	$ 1,228,958	$ 1,228,958	$ 1,228,958
24							
25	Required Percentage Increase In Revenue (Line 19 / Line 21)	21.36%	21.36%	21.36%	12.11%	12.11%	12.11%
26							
27	Rate Of Return On Common Equity	10.25%	10.25%	10.25%	9.20%	9.20%	9.20%
28							
29	Fair Value in dollars						

References:
Columns (A) Thru (C): Company Schedule A-1, C-1 and D-1
Column (D): RUCO Schedules 3, 14, and 31
Column (E): RUCO RCND
Column (F): RUCO Fair Value

Tucson Electric Power **RUCO Schedule 2**
Docket No. E-01933A-22-0107 **Witness: Michlik**
Test Year Ended December 31, 2021

GROSS REVENUE CONVERSION FACTOR, INCOME TAX CALCULATION

LINE NO.	DESCRIPTION	[A] Company Proposed	[B] RUCO Recommended
1	Gross Operating Revenues	1,000.000	1,000.000
2	Less: Uncollectible Revenue	0.4729%	0.4729%
3	Taxable Income as a Percent	995.27	995.27
4	Less: State Income Tax	3.9113%	3.9113%
5	Sub Total	956.34	956.34
6	Less: Federal Income Taxes	21.0000%	21.0000%
7	Total	747.34	747.34
8			
9	Gross Revenue Conversion Factor	1.3381	1.3381

References:
Column [A]: Company as Filed
Column [B]: RUCO Recommended

Tucson Electric Power
Docket No. E-01933A-22-0107
Test Year Ended December 31, 2021

RUCO Schedule 3
Witness: Brown

RATE BASE (OCRB, RCND and FVRB)
ACC JURISDICTIONAL

LINE NO.	Description	(A) COMPANY OCRB	(B) COMPANY RCND	(C) COMPANY FVRB	(D) OCRB/RCND % DIFF.	(E) RUCO OCRB	(F) RUCO RCND	(G) RUCO FVRB
1	Gross Utility Plant in Service	$ 6,382,682,269	$ 12,829,137,385	$ 9,605,909,827	201.00%	$ 6,291,897,170	$ 12,707,615,542	$ 9,499,756,356
2	Less: Accumulated Depreciation	2,263,682,182	4,896,991,067	3,580,336,625	216.33%	2,266,882,994	4,980,158,695	3,623,520,845
3	Net Utility Plant in Service	$ 4,119,000,086	$ 7,932,146,319	$ 6,025,573,202		$ 4,025,014,176	$ 7,727,456,846	$ 5,876,235,511
4								
5	Plant Held for Future Use	-	-	-		-	-	-
6	Total Net Utility Plant in Service	$ 4,119,000,086	$ 7,932,146,319	$ 6,025,573,202		$ 4,025,014,176	$ 7,727,456,846	$ 5,876,235,511
7								
8	Customer Advances for Construction	$ (15,077,376)	$ (16,378,538)	$ (15,727,957)	108.63%	$ (15,077,376)	$ (16,378,538)	$ (15,727,957)
9	Customer Deposits	(12,995,725)	(12,995,725)	(12,995,725)	100.00%	(12,995,725)	(12,995,725)	(12,995,725)
10	Accumulated Deferred Investment Tax Credits	-	-	-		-	-	-
11	Accumulated Deferred Income Taxes	(481,355,035)	(1,042,357,899)	(761,856,467)	216.55%	(473,630,450)	(1,034,633,314)	(754,131,882)
12	Total Deductions	$ (509,428,136)	$ (1,071,732,162)	$ (790,580,149)		$ (501,703,551)	$ (1,064,007,577)	$ (782,855,564)
13								
14	Allowance for Working Capital	$ 154,487,303	$ 154,487,303	$ 154,487,303	100.00%	$ 153,481,739	$ 153,481,739	$ 153,481,739
15								
16	Other Rate Base Adjustments	(2,328,164)	(2,328,164)	(2,328,164)	100.00%	(2,328,164)	(2,328,164)	(2,328,164)
17								
18	Regulatory Assets	68,615,467	68,615,467	68,615,467	100.00%	33,223,154	33,223,154	33,223,154
19								
20	Regulatory Liabilities	(205,198,669)	(205,198,669)	(205,198,669)	100.00%	(205,198,669)	(205,198,669)	(205,198,669)
21				-				
22	Total Original Cost Rate Base	$ 3,625,147,888	$ 6,875,990,094	$ 5,250,568,991		$ 3,502,488,686	$ 6,642,627,330	$ 5,072,558,008

References:
Columns (A) (B) (C): Company Schedule B-1
Column (D): Column (B) / Column (A)
Column (E): RUCO Schedule 4, Column (C)
Column (F): RUCO - Schedule 6, Column (C)
Column (G): Average of Column (E) + Column (F) / 2

Tucson Electric Power
Docket No. E-01933A-22-0107
Test Year Ended December 31, 2021

RUCO Schedule 4
Witness: Brown

ORIGINAL COST RATE BASE - ACC JURISDICTIONAL

LINE NO.	Description	(A) COMPANY AS FILED OCRB	(B) RUCO ADJUSTMENTS	(C) RUCO AS ADJUSTED OCRB
1	Gross Utility Plant in Service	$ 6,382,682,269	$ (90,785,098)	$ 6,291,897,170
2	Less: Accumulated Depreciation	2,263,682,182	3,200,812	2,266,882,994
3	Net Utility Plant in Service	$ 4,119,000,086	$ (93,985,910)	$ 4,025,014,176
4				
5	Plant Held for Future Use	-	-	-
6	Total Net Utility Plant in Service	$ 4,119,000,086	$ (93,985,910)	$ 4,025,014,176
7				
8	Customer Advances for Construction	$ (15,077,376)	$ -	$ (15,077,376)
9	Customer Deposits	(12,995,725)	-	(12,995,725)
10	Accumulated Deferred Investment Tax Credits	-	-	-
11	Accumulated Deferred Income Taxes	(481,355,035)	7,724,585	(473,630,450)
12	Total Deductions	$ (509,428,136)	$ 7,724,585	$ (501,703,551)
13		-		-
14	Allowance for Working Capital	$ 154,487,303	$ (1,005,564)	$ 153,481,739
15				
16	Other Rate Base Adjustments	(2,328,164)	-	(2,328,164)
17				
18	Regulatory Assets	68,615,467	(35,392,313)	33,223,154
19				
20	Regulatory Liabilities	(205,198,669)	-	(205,198,669)
21				
22	Total Original Cost Rate Base	$ 3,625,147,888	$ (122,659,202)	$ 3,502,488,686

References:
Column [A]: Company as Filed
Column [B]: RUCO Schedule 5
Column (C): Column (A) + Column (B)

Tucson Electric Power
Docket No. E-01933A-22-0107
Test Year Ended December 31, 2021

SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

		ACC Jurisdiction			
Line No.	DESCRIPTION	(A) Company Adjusted OCRB As Filed	(B) Rate Base Adjustment No. 1 Rountine PTYP Adjustment	(C) Rate Base Adjustment No. 2 Post-Test Year Plant Retirements	(D) Rate Base Adjustment No. 3 Accumulated Depreciation
1	Gross Utility Plant in Service	$ 6,382,682,269	$ (830,608)	$ (89,954,490)	$ -
2	Less: Accumulated Depreciation	2,263,682,182	-	-	3,200,812
3	Net Utility Plant in Service	$ 4,119,000,086	$ (830,608)	$ (89,954,490)	$ (3,200,812)
4					
5	Plant Held for Future Use	-	-	-	-
6	Total Net Utility Plant in Service	$ 4,119,000,086	$ (830,608)	$ (89,954,490)	$ (3,200,812)
7					
8	Customer Advances for Construction	$ (15,077,376)	$ -	$ -	$ -
9	Customer Deposits	(12,995,725)	-	-	-
10	Accumulated Deferred Investment Tax Credits	-	-	-	-
11	Accumulated Deferred Income Taxes	(481,355,035)	-	-	-
12	Total Deductions	$ (509,428,136)	$ -	$ -	$ -
13					
14	Allowance for Working Capital	$ 154,487,303	$ -	$ -	$ -
15					
16	Other Rate Base Adjustments	(2,328,164)	-	-	-
17					
18	Regulatory Assets	68,615,467	-	-	-
19					
20	Regulatory Liabilities	(205,198,669)	-	-	-
21					
22	Total Original Cost Rate Base	$ 3,625,147,887	$ (830,608)	$ (89,954,490)	$ (3,200,812)

REFERENCES:
Column (A) Company Schedule B-1
Column (B) See RUCO Schedule 8
Column (C) See RUCO Schedule 9
Column (D) See RUCO Schedule 10
Column (E) See RUCO Schedule 11
Column (F) See RUCO Schedule 12
Column (G) = Column (A) - Column (B) through (F)

Tucson Electric Power
Docket No. E-01933A-22-0107
Test Year Ended December 31, 2021

SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

Line No.	DESCRIPTION	ACC Jurisdiction (A) Company Adjusted OCRB As Filed	(B) Rate Base Adjustment No. 1 Rountine PTYP Adjustment	(C) Rate Base Adjustment No. 2 Post-Test Year Plant Retirements	(D) Rate Base Adjustment No. 3 Accumulated Depreciation	ACC Jurisdiction (E) Rate Base Adjustment No. 4 Cash Working Capital	(F) Rate Base Adjustment No. 5 Regulatory Assets and Related ADIT	(G) RUCO Adjusted OCRB Recommended Balances
1	Gross Utility Plant in Service	$ 6,382,682,269	$ (830,608)	$ (89,954,490)	$ -	$ -	$ -	$ 6,291,897,170
2	Less: Accumulated Depreciation	2,263,682,182	-	-	3,200,812	-	-	2,266,882,994
3	Net Utility Plant in Service	$ 4,119,000,086	$ (830,608)	$ (89,954,490)	$ (3,200,812)	$ -	$ -	$ 4,025,014,176
4								
5	Plant Held for Future Use	-	-	-	-	-	-	-
6	Total Net Utility Plant in Service	$ 4,119,000,086	$ (830,608)	$ (89,954,490)	$ (3,200,812)	$ -	$ -	$ 4,025,014,176
7								
8	Customer Advances for Construction	$ (15,077,376)	$ -	$ -	$ -	$ -	$ -	$ (15,077,376)
9	Customer Deposits	(12,995,725)	-	-	-	-	-	(12,995,725)
10	Accumulated Deferred Investment Tax Credits	-	-	-	-	-	-	-
11	Accumulated Deferred Income Taxes	(481,355,035)	-	-	-	-	7,724,585	(473,630,450)
12	Total Deductions	$ (509,428,136)	$ -	$ -	$ -	$ -	$ 7,724,585	$ (501,703,551)
13								
14	Allowance for Working Capital	$ 154,487,303	$ -	$ -	$ -	$ (1,005,564)	$ -	$ 153,481,739
15								
16	Other Rate Base Adjustments	(2,328,164)	-	-	-	-	-	(2,328,164)
17								
18	Regulatory Assets	68,615,467	-	-	-	-	(35,392,313)	33,223,154
19								
20	Regulatory Liabilities	(205,198,669)	-	-	-	-	-	(205,198,669)
21								
22	Total Original Cost Rate Base	$ 3,625,147,887	$ (830,608)	$ (89,954,490)	$ (3,200,812)	$ (1,005,564)	$ (27,667,728)	$ 3,502,488,686

REFERENCES:
Column (A) Company Schedule B-1
Column (B) See RUCO Schedule 8
Column (C) See RUCO Schedule 9
Column (D) See RUCO Schedule 10
Column (E) See RUCO Schedule 11
Column (F) See RUCO Schedule 12
Column (G) = Column (A) - Column (B) through (F)

Tucson Electric Power
Docket No. E-01933A-22-0107
Test Year Ended December 31, 2021

RUCO Schedule 6
Witness: Brown

RECONSTRUCTION COST NEW LESS DEPRECIATION ("RCND") RATE BASE - ACC JURISDICTIONAL

LINE NO.	Description	(A) COMPANY AS FILED RCND	(B) RUCO ADJUSTMENTS	(C) RUCO AS ADJUSTED RCND
1	Gross Utility Plant in Service	$ 12,829,137,385	$ (121,521,844)	$ 12,707,615,542
2	Less: Accumulated Depreciation	4,896,991,067	83,167,629	4,980,158,695
3	Net Utility Plant in Service	$ 7,932,146,319	$ (204,689,472)	$ 7,727,456,846
4				
5	Plant Held for Future Use	-	-	-
6	Total Net Utility Plant in Service	$ 7,932,146,319	$ (204,689,472)	$ 7,727,456,846
7				
8	Customer Advances for Construction	$ (16,378,538)	$ -	$ (16,378,538)
9	Customer Deposits	(12,995,725)	-	(12,995,725)
10	Accumulated Deferred Investment Tax Credits	-	-	-
11	Accumulated Deferred Income Taxes	(1,042,357,899)	7,724,585	(1,034,633,314)
12	Total Deductions	$ (1,071,732,162)	$ 7,724,585	$ (1,064,007,577)
13				
14	Allowance for Working Capital	$ 154,487,303	$ (1,005,564)	$ 153,481,739
15				
16	Other Rate Base Adjustments	(2,328,164)	-	(2,328,164)
17				
18	Regulatory Assets	68,615,467	(35,392,313)	33,223,154
19				
20	Regulatory Liabilities	(205,198,669)	-	(205,198,669)
21				
22	Total Original Cost Rate Base	$ 6,875,990,093	$ (233,362,764)	$ 6,642,627,329

References:
Column [A]: Company as Filed
Column [B]: RUCO Schedule 7
Column (C): Column (A) + Column (B)

SUMMARY OF RECONSTRUCTION COST NEW LESS DEPRECIATION ADJUSTMENTS

		ACC Jurisdiction			
Line No.	DESCRIPTION	(A) Company Adjusted RCND As Filed	(B) Rate Base Adjustment No. 1 Rountine PTYP Adjustment	(C) Rate Base Adjustment No. 2 Post-Test Year Plant Retirements	(D) Rate Base Adjustment No. 3 Accumulated Depreciation
1	Gross Utility Plant in Service	$ 12,829,137,385	$ (830,608)	$ (120,691,236)	$ -
2	Less: Accumulated Depreciation	4,896,991,067	-	-	83,167,629
3	Net Utility Plant in Service	$ 7,932,146,319	$ (830,608)	$ (120,691,236)	$ (83,167,629)
4					
5	Plant Held for Future Use	-	-	-	-
6	Total Net Utility Plant in Service	$ 7,932,146,319	$ (830,608)	$ (120,691,236)	$ (83,167,629)
7					
8	Customer Advances for Construction	$ (16,378,538)	$ -	$ -	$ -
9	Customer Deposits	(12,995,725)	-	-	-
10	Accumulated Deferred Investment Tax Credits	-	-	-	-
11	Accumulated Deferred Income Taxes	(1,042,357,899)	-	-	-
12	Total Deductions	$ (1,071,732,162)	$ -	$ -	$ -
13					
14	Allowance for Working Capital	$ 154,487,303	$ -	$ -	$ -
15					
16	Other Rate Base Adjustments	(2,328,164)	-	-	-
17					
18	Regulatory Assets	68,615,467	-	-	-
19					
20	Regulatory Liabilities	(205,198,669)	-	-	-
21					
22	Total RCND Rate Base	$ 6,875,990,093	$ (830,608)	$ (120,691,236)	$ (83,167,629)

REFERENCES:
Column (A) Company Schedule B-1
Column (B) See RUCO Schedule 8
Column (C) See RUCO Schedule 9
Column (D) See RUCO Schedule 10
Column (E) See RUCO Schedule 11
Column (F) See RUCO Schedule 12
Column (G) = Column (A) - Column (B) through (F)

Tucson Electric Power
Docket No. E-01933A-22-0107
Test Year Ended December 31, 2021

SUMMARY OF RECONSTRUCTION COST NEW LESS DEPRECIATION ADJUSTMENTS

SUMMARY OF RECONSTRUCTION COST NEW LESS DEPRECIATION ADJUSTMENTS

Line No.	DESCRIPTION	(A) Company Adjusted RCND As Filed	(B) Rate Base Adjustment No. 1 Rountine PTYP Adjustment	(C) Rate Base Adjustment No. 2 Post-Test Year Plant Retirements	(D) Rate Base Adjustment No. 3 Accumulated Depreciation	(E) Rate Base Adjustment No. 4 Cash Working Capital	(F) Rate Base Adjustment No. 5 Regulatory Assets and Related ADIT	(G) RUCO Adjusted RCND Recommended Balances
		ACC Jurisdiction				ACC Jurisdiction		
1	Gross Utility Plant in Service	$ 12,829,137,385	$ (830,608)	$ (120,691,236)	$ -	$ -	$ -	$ 12,707,615,542
2	Less: Accumulated Depreciation	4,896,991,067	-	-	83,167,629	-	-	4,980,158,695
3	Net Utility Plant in Service	$ 7,932,146,319	$ (830,608)	$ (120,691,236)	$ (83,167,629)	$ -	$ -	$ 7,727,456,846
4								
5	Plant Held for Future Use	-	-	-	-	-	-	-
6	Total Net Utility Plant in Service	$ 7,932,146,319	$ (830,608)	$ (120,691,236)	$ (83,167,629)	$ -	$ -	$ 7,727,456,846
7								
8	Customer Advances for Construction	$ (16,378,538)	$ -	$ -	$ -	$ -	$ -	$ (16,378,538)
9	Customer Deposits	(12,995,725)	-	-	-	-	-	(12,995,725)
10	Accumulated Deferred Investment Tax Credits	-	-	-	-	-	-	-
11	Accumulated Deferred Income Taxes	(1,042,357,899)	-	-	-	-	7,724,585	(1,034,633,314)
12	Total Deductions	$ (1,071,732,162)	$ -	$ -	$ -	$ -	$ 7,724,585	$ (1,064,007,577)
13								
14	Allowance for Working Capital	$ 154,487,303	$ -	$ -	$ -	$ (1,005,564)	$ -	$ 153,481,739
15								
16	Other Rate Base Adjustments	(2,328,164)	-	-	-	-	-	(2,328,164)
17								
18	Regulatory Assets	68,615,467	-	-	-	-	(35,392,313)	33,223,154
19								
20	Regulatory Liabilities	(205,198,669)	-	-	-	-	-	(205,198,669)
21								
22	Total RCND Rate Base	$ 6,875,990,093	$ (830,608)	$ (120,691,236)	$ (83,167,629)	$ (1,005,564)	$ (27,667,728)	$ 6,642,627,329

REFERENCES:
Column (A) Company Schedule B-1
Column (B) See RUCO Schedule 8
Column (C) See RUCO Schedule 9
Column (D) See RUCO Schedule 10
Column (E) See RUCO Schedule 11
Column (F) See RUCO Schedule 12
Column (G) = Column (A) - Column (B) through (F)

Tucson Electric Power
Docket No. E-01933A-22-0107
Test Year Ended December 31, 2021

RUCO Schedule 8
Witness: Brown

RATE BASE ADJUSTMENT NO. 1
REMOVE ROUTINE POST-TEST YEAR PLANT

			[A]	[B]	[C]		[D]	[E]	[F]
			Original Cost			RCN	Reconstructive Cost New		
Line No.	FERC Nos.	DESCRIPTION	Company Proposed	RUCO Adjustment	RUCO As Adjusted	Ratio Factor	Company Proposed	RUCO Adjustment	RUCO As Adjusted
1		Gross Utility Plant in Service	$ 6,382,682,269	$ -	$ 6,382,682,269		$ 12,829,137,385	$ -	$ 12,829,137,385
2	391	To Remove PTY Office Furniture	-	(830,608)	(830,608)	1.00	-	(830,608)	(830,608)
3		Total	$ 6,382,682,269	$ (830,608)	$ 6,381,851,661		$ 12,829,137,385	$ (830,608)	$ 12,828,306,777

Source: RUCO Data Request 1.41

References:
Column [A] Per Company Filing
Column [B] Testimony CSB
Column [C] = Column [A] + Column [B]
Column [D] = Column [A] x RCND Ratio Factor
Column [E] = Column [B] x RCND Ratio Factor
Column [F] = Column [D] + Column [E]

Tucson Electric Power
Docket No. E-01933A-22-0107
Test Year Ended December 31, 2021

RATE BASE ADJUSTMENT NO. 2
POST-TEST YEAR PLANT RETIREMENTS JANUARY to JUNE 2022

			[A]	[B]	[C]	[D]	[E]	[F]	[G]
			Original Cost			RCN	Reconstructive Cost New		
Line No.	FERC Nos.	DESCRIPTION	Company Proposed	RUCO Adjustment	RUCO As Adjusted	Ratio Factor	Company Proposed	RUCO Adjustment	RUCO As Adjusted
				RUCO DR 1.37	Column A + B	From Sch 9, P.3		Col B x Col D	Col E + Col F
1	317	ARCs for Steam Production Plant	$ -	$ -	$ -	1.0000	$ -	$ -	$ -
2	303	Miscellaneous Intangible Plant	$ -	$ (56,532,815)	$ (56,532,815)	1.1619	$ -	$ (65,682,717)	$ (65,682,717)
3	311	Structures & Improvements	$ -	$ (636,845)	$ (636,845)	2.6826	$ -	$ (1,708,382)	$ (1,708,382)
4	312	Boiler Plant Equipment	$ -	$ (7,569,574)	$ (7,569,574)	2.2817	$ -	$ (17,271,779)	$ (17,271,779)
5	314	Turbogenerator Units	$ -	$ (1,329,319)	$ (1,329,319)	2.2948	$ -	$ (3,050,494)	$ (3,050,494)
6	315	Accessory Electric Equipment	$ -	$ (442,282)	$ (442,282)	4.5397	$ -	$ (2,007,813)	$ (2,007,813)
7	316	Miscellaneous Power Plant Equipment	$ -	$ (105,087)	$ (105,087)	2.3133	$ -	$ (243,098)	$ (243,098)
8	341	Structures & Improvements	$ -	$ (25,905)	$ (25,905)	1.5068	$ -	$ (39,034)	$ (39,034)
9	342	Fuel Holders, Producers, & Accessories	$ -	$ (5,186)	$ (5,186)	1.8454	$ -	$ (9,570)	$ (9,570)
10	343	Prime Movers	$ -	$ (717,632)	$ (717,632)	1.6404	$ -	$ (1,177,169)	$ (1,177,169)
11	344	Generators	$ -	$ (632,926)	$ (632,926)	1.5202	$ -	$ (962,172)	$ (962,172)
12	345	Accessory Electric Equipment	$ -	$ (154,564)	$ (154,564)	1.5936	$ -	$ (246,308)	$ (246,308)
13	346	Miscellaneous Power Plant Equipment	$ -	$ -	$ -	1.9619	$ -	$ -	$ -
14	352	Structures & Improvements	$ -	$ (9,466)	$ (9,466)	1.6719	$ -	$ (15,826)	$ (15,826)
15	353	Station Equipment	$ -	$ (1,004,500)	$ (1,004,500)	2.0025	$ -	$ (2,011,534)	$ (2,011,534)
16	355	Poles & Fixtures	$ -	$ (299,935)	$ (299,935)	1.2017	$ -	$ (360,422)	$ (360,422)
17	356	Overhead Conductors & Devices	$ -	$ (88,024)	$ (88,024)	1.8490	$ -	$ (162,753)	$ (162,753)
18	360	Land & Rights	$ -	$ (18,995)	$ (18,995)	1.0000	$ -	$ (18,995)	$ (18,995)
19	361	Structures & Improvements	$ -	$ (31,783)	$ (31,783)	1.5480	$ -	$ (49,198)	$ (49,198)
20	362	Station Equipment	$ -	$ (1,123,389)	$ (1,123,389)	2.0408	$ -	$ (2,292,604)	$ (2,292,604)
21	364	Poles, Towers, & Fixtures	$ -	$ (463,966)	$ (463,966)	1.7966	$ -	$ (833,584)	$ (833,584)
22	365	Overhead Conductors & Devices	$ -	$ (240,452)	$ (240,452)	2.0538	$ -	$ (493,849)	$ (493,849)
23	366	Underground Conduit	$ -	$ (134,655)	$ (134,655)	1.8813	$ -	$ (253,328)	$ (253,328)
24	367	Underground Conductors & Devices	$ -	$ (320,569)	$ (320,569)	2.4389	$ -	$ (781,843)	$ (781,843)
25	368	Line Transformers	$ -	$ (429,559)	$ (429,559)	3.0458	$ -	$ (1,308,351)	$ (1,308,351)
26	369	Services	$ -	$ (32,417)	$ (32,417)	1.7904	$ -	$ (58,038)	$ (58,038)
27	370	Meters	$ -	$ (3,459,886)	$ (3,459,886)	1.0582	$ -	$ (3,661,234)	$ (3,661,234)
28	373	Street Lighting & Signal Systems	$ -	$ (38,588)	$ (38,588)	1.7377	$ -	$ (67,053)	$ (67,053)
29	390	Structures & Improvements	$ -	$ (3,383,865)	$ (3,383,865)	1.3045	$ -	$ (4,414,370)	$ (4,414,370)
30	391	Office Furniture & Equipment	$ -	$ (4,168,313)	$ (4,168,313)	1.1045	$ -	$ (4,604,075)	$ (4,604,075)
31	392	Transportation Equipment	$ -	$ (419,096)	$ (419,096)	1.1181	$ -	$ (468,607)	$ (468,607)
32	393	Stores Equipment	$ -	$ (77,542)	$ (77,542)	1.2345	$ -	$ (95,724)	$ (95,724)
33	394	Tools, Shop, & Garage Equipment	$ -	$ (196,318)	$ (196,318)	1.1788	$ -	$ (231,427)	$ (231,427)
34	395	Laboratory Equipment	$ -	$ (332,225)	$ (332,225)	1.0526	$ -	$ (349,699)	$ (349,699)
35	396	Power Operated Equipment	$ -	$ -	$ -	1.1190	$ -	$ -	$ -
36	397	Communication Equipment	$ -	$ (5,528,814)	$ (5,528,814)	1.0418	$ -	$ (5,760,186)	$ (5,760,186)
		Total	$ -	$ (89,954,490)	$ (89,954,490)		$ -	$ (120,691,236)	$ (120,691,236)

Tucson Electric Power
Docket No. E-01933A-22-0107
Test Year Ended December 31, 2021

Witness: Brown

To Remove San Juan PTY Retirements From "All" PTY Retirements Reported in RUCO DR 1.37

Line No.	FERC Nos.	DESCRIPTION		[A] All PTY Retirements Jan to June 2022		[B] To Remove San Juan Retirements From the Retirements Included in RUCO DR 1.37		[C] PTY Retirements
				RUCO DR 1.37		RUCO DR 10.01		Column A + B
1	317	ARCs for Steam Production Plant	$	(18,239,070)	$	18,239,070	$	-
2	303	Miscellaneous Intangible Plant	$	(56,690,289)	$	157,474	$	(56,532,815)
3	311	Structures & Improvements	$	(21,079,109)	$	20,442,265	$	(636,845)
4	312	Boiler Plant Equipment	$	(206,923,010)	$	199,353,436	$	(7,569,574)
5	314	Turbogenerator Units	$	(43,536,521)	$	42,207,201	$	(1,329,319)
6	315	Accessory Electric Equipment	$	(18,115,914)	$	17,673,632	$	(442,282)
7	316	Miscellaneous Power Plant Equipment	$	(2,352,658)	$	2,247,572	$	(105,087)
8	341	Structures & Improvements	$	(25,905)	$	-	$	(25,905)
9	342	Fuel Holders, Producers, & Accessories	$	(5,186)	$	-	$	(5,186)
10	343	Prime Movers	$	(717,632)	$	-	$	(717,632)
11	344	Generators	$	(632,926)	$	-	$	(632,926)
12	345	Accessory Electric Equipment	$	(154,564)	$	-	$	(154,564)
13	346	Miscellaneous Power Plant Equipment	$	-	$	-	$	-
14	352	Structures & Improvements	$	(9,466)	$	-	$	(9,466)
15	353	Station Equipment	$	(1,004,500)	$	-	$	(1,004,500)
16	355	Poles & Fixtures	$	(299,935)	$	-	$	(299,935)
17	356	Overhead Conductors & Devices	$	(88,024)	$	-	$	(88,024)
18	360	Land & Rights	$	(18,995)	$	-	$	(18,995)
19	361	Structures & Improvements	$	(31,783)	$	-	$	(31,783)
20	362	Station Equipment	$	(1,123,389)	$	-	$	(1,123,389)
21	364	Poles, Towers, & Fixtures	$	(463,966)	$	-	$	(463,966)
22	365	Overhead Conductors & Devices	$	(240,452)	$	-	$	(240,452)
23	366	Underground Conduit	$	(134,655)	$	-	$	(134,655)
24	367	Underground Conductors & Devices	$	(320,569)	$	-	$	(320,569)
25	368	Line Transformers	$	(429,559)	$	-	$	(429,559)
26	369	Services	$	(32,417)	$	-	$	(32,417)
27	370	Meters	$	(3,459,886)	$	-	$	(3,459,886)
28	373	Street Lighting & Signal Systems	$	(38,588)	$	-	$	(38,588)
29	390	Structures & Improvements	$	(4,241,552)	$	857,687	$	(3,383,865)
30	391	Office Furniture & Equipment	$	(4,958,696)	$	790,383	$	(4,168,313)
31	392	Transportation Equipment	$	(819,426)	$	400,329	$	(419,096)
32	393	Stores Equipment	$	(113,189)	$	35,647	$	(77,542)
33	394	Tools, Shop, & Garage Equipment	$	(244,518)	$	48,200	$	(196,318)
34	395	Laboratory Equipment	$	(332,225)	$	-	$	(332,225)
35	396	Power Operated Equipment	$	(137,937)	$	137,937	$	-
36	397	Communication Equipment	$	(5,965,990)	$	437,177	$	(5,528,814)
		Total	$	(392,982,501)	$	303,028,010	$	(89,954,490)

Calculation of RCN Ratio Factor

FERC Account	Plant In Service	OCRB Adjusted Plant in Service	RCND Adjusted Plant in Service	RCN Ratio Factor (RCND / OCRB)
317	ARCs for Steam Production Plant	0	0	**1.000000**
303	Miscellaneous Intangible Plant	306,119,534	355,665,335	**1.161851**
311	Structures & Improvements	349,121,877	936,544,173	**2.682571**
312	Boiler Plant Equipment	1,210,446,796	2,761,921,661	**2.281737**
314	Turbogenerator Units	300,279,917	689,076,057	**2.294779**
315	Accessory Electric Equipment	192,905,641	875,727,260	**4.539666**
316	Miscellaneous Power Plant Equipment	33,042,844	76,438,283	**2.313308**
341	Structures & Improvements	67,651,365	101,938,885	**1.506827**
342	Fuel Holders, Producers, & Accessories	28,947,979	53,420,129	**1.845384**
343	Prime Movers	531,855,343	872,430,029	**1.640352**
344	Generators	785,706,535	1,194,428,788	**1.520197**
345	Accessory Electric Equipment	116,824,240	186,167,102	**1.593566**
346	Miscellaneous Power Plant Equipment	27,717,393	54,377,688	**1.961862**
352	Structures & Improvements	75,930,807	126,949,382	**1.671909**
353	Station Equipment	560,478,706	1,122,371,422	**2.002523**
355	Poles & Fixtures	168,016,163	201,899,383	**1.201666**
356	Overhead Conductors & Devices	145,386,456	268,814,775	**1.848967**
360	Land & Rights	11,194,440	11,194,442	**1.000000**
361	Structures & Improvements	29,395,787	45,503,521	**1.547961**
362	Station Equipment	363,060,098	740,930,602	**2.040793**
364	Poles, Towers, & Fixtures	328,433,552	590,079,356	**1.796648**
365	Overhead Conductors & Devices	259,298,246	532,555,331	**2.053833**
366	Underground Conduit	93,779,353	176,427,990	**1.881310**
367	Underground Conductors & Devices	383,740,766	935,914,786	**2.438925**
368	Line Transformers	345,274,427	1,051,637,604	**3.045802**
369	Services	185,629,951	332,349,273	**1.790386**
370	Meters	91,950,398	97,301,432	**1.058195**
373	Street Lighting & Signal Systems	19,226,896	33,409,712	**1.737655**
390	Structures & Improvements	282,427,901	368,437,128	**1.304535**
391	Office Furniture & Equipment	124,220,907	137,207,160	**1.104542**
392	Transportation Equipment	58,266,422	65,149,756	**1.118136**
393	Stores Equipment	1,603,147	1,979,070	**1.234491**
394	Tools, Shop, & Garage Equipment	11,022,821	12,994,098	**1.178836**
395	Laboratory Equipment	6,502,964	6,844,998	**1.052597**
396	Power Operated Equipment	13,785,785	15,426,245	**1.118996**
397	Communication Equipment	142,850,671	148,828,743	**1.041848**

Tucson Electric Power
Docket No. E-01933A-22-0107
Test Year Ended December 31, 2021

RUCO Schedule 10
Witness: Brown

RATE BASE ADJUSTMENT NO. 3
ACCUMULATED DEPRECIATION & AMORTIZATION

LINE NO.	Description	[A] Original Cost COMPANY AS FILED	[B] Original Cost RUCO ADJUSTMENTS	[C] Original Cost RUCO AS ADJUSTED	[D] RCN RATIO FACTOR	[E] RCN COMPANY AS FILED	[F] RCN RUCO ADJUSTMENTS	[G] RCN RUCO AS ADJUSTED
1		Ref: Sch B-1, Page 1					Col B x Col D	
2	Accumulated Depreciation & Amortization	$ 2,263,682,182	$ -	$ 2,263,682,182		$ 2,263,682,182	$ -	$ 2,263,682,182
3	To Reflect PTY Depreciation Exp to Same Cut-off Date as PTY Plant	$ -	$ 95,164,560	$ 95,164,560	2.16	$ -	$ 205,868,122	$ 205,868,122
4	To Remove Accu Depr for Routine PTY Office Furniture & Equip	$ -	$ (8,680)	$ (8,680)	1.00	$ -	$ (8,680)	$ (8,680)
5	To Remove Accu Depr for PTY Retirements (**See RUCO Schedule 9**)	$ -	$ (89,954,490)	$ (89,954,490)	RUCO Sch 9	$ -	$ (120,691,236)	$ (120,691,236)
6	To Remove Amortization Exp for Demand Side Mgmnt Regulatory Asset (**From Line 30**)	$ -	$ (1,511,926)	$ (1,511,926)	1.00	$ -	$ (1,511,926)	$ (1,511,926)
7	To Remove Amortization Exp for Electric Vehicle Infrastruc. Regulatory Asset (**From Line 30**)	$ -	$ (253,514)	$ (253,514)	1.00	$ -	$ (253,514)	$ (253,514)
8	To Remove Amortization Exp for San Juan Materials & Supplies Regulatory Asset (**From Line 30**)	$ -	$ (235,138)	$ (235,138)	1.00	$ -	$ (235,138)	$ (235,138)
9	**Total Accumulated Depreciation & Amortization**	$ 2,263,682,182	$ 3,200,812	$ 2,266,882,994		$ 2,263,682,182	$ 83,167,629	$ 2,346,849,811
10								
11								

LINE NO.			
12	To Reflect 6-Months of PTY Depreciation		
13	Test Year Depreciation	$ 190,329,120	RUCO Schedule 13
14	Divided by 2	2	
15		$ 95,164,560	
16			
17			
18	Calculation of		
19	Half Year Convention Depreciation Expense		
20	**for PTY Office Furniture**		
21	Plant to Be Removed	$ 830,608	RUCO 1.41
22	Multiplied by	4.18%	From Depreciation Study
23		$ 34,719	
24	Multiplied by	3/12	To reflect plant being removed at midpoint of 6 month cut off period
25	Total Removed	$ 8,680	
26			
27			

LINE NO.	**Calculation of Amortization Expense for Regulatory Assets**				
28					
29-31		**Demand Side Management**	**Electric Vehicle Infrastructure Investments**	**San Juan Materials & Supplies**	
32		RUCO DR 3.15	RUCO DR 3.15	RUCO DR 3.15	
33	Annual Amortization Expense Related to Regulatory Assets to Be Removed	$ 6,047,705	$ 1,014,054	$ 940,552	
34		3/12	3/12	3/12	To reflect plant being removed at midpoint of 6 months
35		$ 1,511,926	$ 253,514	$ 235,138	

Column A: Company Schedule B-1
Column B: RUCO Schedule 4; Testimony, CSB
Column C: Column [A] + Column [B]

RATE BASE ADJUSTMENT NO. 4
WORKING CAPITAL SUMMARY

Line No.	Description	(A) Per Company	(B) Adjustment	(C) Per RUCO	
		Co. Sch B5 P-1	Col C - Col A		
1	Cash Working Capital	$ (9,930,742)	(1,005,564)	$ (10,936,306)	RUCO Schedule 11, Page 2, Line 30
2					
3	Fuel Inventory	$ 25,141,000	0	$ 25,141,000	
4					
5	Materials and Supplies	$ 122,918,000	0	$ 122,918,000	
6					
7	Prepayments	$ 16,357,000	0	$ 16,357,000	
8					
9	Total Working Capital	$ 154,485,258	$ (1,005,564)	$ 153,479,694	

RATE BASE ADJUSTMENT NO. 4
Cash Working Capital - Lead/Lag Study

Line No.	(A) Description	(B) RUCO Adjusted Test Year Amount	(C) Revenue Lag Days	(D) Expense Lag Days	(E) Net Lag Days	(F) Lead/Lag Factor	(G) Cash Working Capital Required
		Ref: RUCO Sch 11, P.3	Ref: Co. Sch B5, P-3	Ref: RUCO Sch 11, **P.4**	Col. C - Col. D	Col. E / 365	Col. B x Col. F
	Cash Operating Expenses -						
1	Salaries and Wages	95,635,147	42.19	10.94	31.25	0.0856	8,186,369
2	Incentive Pay	1,029,603	42.19	244.50	(202.31)	(0.5543)	(570,709)
3	Intercompany	22,873,629	42.19	39.49	2.70	0.0074	169,265
4	Fuel & Purchased Power Expense	383,316,622	42.19	32.79	9.40	0.0258	9,889,569
5	Other O&M	38,703,823	42.19	30.84	11.35	0.0311	1,203,689
6	Remote Generating Plants O&M	30,535,041	42.19	(3.26)	45.45	0.1245	3,801,613
7	Office Supplies and Expenses	12,578,572	42.19	(39.77)	81.96	0.2245	2,823,889
8	Outside Services	12,144,353	42.19	42.82	(0.63)	(0.0017)	(20,645)
9	Property Insurance	0	42.19	0.00	42.19	0.1156	-
10	Injuries and Damages	0	42.19	0.00	42.19	0.1156	-
11	Pensions and Benefits	9,508,340	42.19	153.87	(111.68)	(0.3060)	(2,909,552)
12	Regulatory Commission Expense	1	42.19	0.00	42.19	0.1156	0
13	General Advertising Expenses	1,557,598	42.19	38.10	4.09	0.0112	17,445
14	Miscellaneous General Expenses	2,208,892	42.19	(96.14)	138.33	0.3790	837,170
15	Property Taxes	52,649,440	42.19	212.00	(169.81)	(0.4652)	(24,492,519)
16	Payroll Taxes	6,877,259	42.19	10.94	31.25	0.0856	588,693
17	Current Income Taxes	0	42.19	37.00	5.19	0.0142	-
18	Other Taxes	11,905	42.19	88.63	(46.44)	(0.1272)	(1,514)
19	Interest on Customer Deposits	241,025	42.19	182.50	(140.31)	(0.3844)	(92,650)
20	Other Operations and Maintenance	2,572,393	42.19	35.62	6.57	0.0180	46,303
21	Total Cash Operating Expenses	$672,443,642					($523,585)
22							
23	Other Cash Working Capital Elements:						
24	Interest On Long-Term Debt	61,131,387	42.19	91.25	(49.06)	(0.1344)	(8,216,058)
25	Revenue Taxes and Assessments	106,118,947	42.19	49.74	(7.55)	(0.0207)	(2,196,662)
26		$167,250,334					($10,412,721)
27							
28	Total	$839,693,976					
30					Cash Working Capital - Per RUCO (Line 21 + Line 26)		(10,936,306)

Tucson Electric Power
Docket No. E-01933A-22-0107
Test Year Ended December 31, 2021

RUCO Schedule 11

Witness: Brown

RATE BASE ADJUSTMENT NO. 4
Cash Working Capital - Adjustments to Expenses

	(A)	(B)	(C)	(D)	(E)		(F)
				ACC	RUCO	Adj	RUCO
	Description	Adjusted Total	ACC Ratio	Adjusted Total	Adjustment	No.	as Adjusted
		Ref: Co. Sch B-5, P-3	Ref: Co. Sch B-5, P-3	Col. B x Col. C	Ref: RUCO-14	Ref: RUCO-14	Col D + Col F
	Cash Operating Expenses -						
1	Salaries and Wages	107,147,312	90.40%	96,860,901	(1,225,755)	3, 7a	95,635,147
2	Incentive Pay	10,724,060	90.40%	9,694,523	(8,664,920)	4, 5, 6	1,029,603
3	Intercompany	25,302,757	90.40%	22,873,629	0		22,873,629
4	Fuel & Purchased Power Expense	383,316,622	100.00%	383,316,622	0		383,316,622
5	Other O&M	46,629,194	90.40%	42,152,675	(3,448,852)	2, 8, 9	38,703,823
6	Remote Generating Plants O&M	33,777,794	90.40%	30,535,041	0		30,535,041
7	Office Supplies and Expenses	14,551,089	86.44%	12,578,572	0		12,578,572
8	Outside Services	14,048,779	86.44%	12,144,353	0		12,144,353
9	Property Insurance	5,101,702	79.61%	4,061,673	(4,061,673)	Brown Direct Testimony	-
10	Injuries and Damages	3,161,104	86.44%	2,732,591	(2,732,591)	Brown Direct Testimony	-
11	Pensions and Benefits	10,999,397	86.44%	9,508,340	0		9,508,340
12	Regulatory Commission Expense	5	17.71%	1	0		1
13	General Advertising Expenses	1,801,855	86.44%	1,557,598	0		1,557,598
14	Miscellaneous General Expenses	2,555,281	86.44%	2,208,892	0		2,208,892
15	Property Taxes	64,966,158	81.04%	52,649,440	0		52,649,440
16	Payroll Taxes	7,999,423	86.44%	6,915,036	(37,777)	7b	6,877,259
17	Current Income Taxes	0	0.00%	0	0		-
18	Other Taxes	130,954	9.09%	11,905	0		11,905
19	Interest on Customer Deposits	241,025	100.00%	241,025	0		241,025
20	Other Operations and Maintenance	2,845,575	90.40%	2,572,393	0		2,572,393
21	Total Cash Operating Expenses	$735,300,085		692,615,210	(20,171,568)		$672,443,642
22							
23	Other Cash Working Capital Elements:						
24	Interest On Long-Term Debt	78,251,681	81.04%	63,414,959	(2,283,572)	RUCO-26	61,131,387
25	Revenue Taxes and Assessments	106,118,947	100.00%	106,118,947	0		106,118,947
26		184,370,628		169,533,906	(2,283,572)		167,250,334
27							
28	Total	$919,670,714		$862,149,115	($22,455,140)		$839,693,976

Tucson Electric Power
Docket No. E-01933A-22-0107
Test Year Ended December 31, 2021

Witness: Brown

	Lead Lag Summary Workbook	**Lead Lag Days**	
		From Company Schedule "Lead Lag Days"	
Revenue	A	42.19	
Salaries and Wages	B	10.94	
Incentive Compensation	B	244.50	
Intercompany	C	39.49	
Purchased Power, Trans & Fuel	D	32.79	
Local Generation O&M	E	30.84	
Remote Generating Plants O&M	F	(3.26)	
Office Supply & Expenses	G	(39.77)	
Outside Services	G	42.82	
Pensions & Benefits	G	**153.87**	**See RUCO Workpapers-Confidential Lead Lag Study**
Regulatory Commission Expenses	N/A	-	
General Advertising Expenses	G	38.10	
Misc. General Expense	G	(96.14)	
Property Taxes	H	206.82	
Payroll Taxes	B	10.94	
Income Taxes (See W/P 11.1)	H	37.00	
Other Taxes	H	88.63	
Interest on Customer Deposits	N/A	-	
Other O&M	J	35.62	
Interest on Long-Term Bonds	I	90.60	
Revenue Taxes & Assessments	H	49.74	

Tucson Electric Power
Docket No. E-01933A-22-0107
Test Year Ended December 31, 2021

RUCO Schedule 12
Witness: Erdwurm

RATE BASE ADJUSTMENT NO. 5
REGULATORY ASSETS & RELATED ADIT

Line No.	DESCRIPTION		(A) Company Proposed		(B) RUCO Adjustment		(C) RUCO As Adjusted
1	Demand Side Management (DSM)	$	31,008,731	$	(31,008,731)	$	-
2	Electric Vehicle Infrastructure Investments	$	1,561,925	$	(1,561,925)		
3	San Juan Materials and Supplies	$	2,821,657	$	(2,821,657)		
4		$	35,392,313	$	(35,392,313)	$	-
5							
6							
7	Accumulated Deferred Income Taxes - DSM	$	(7,724,585)	$	7,724,585	$	-
8							

References:
Column (A) Per Company Filing, RUCO Data Request 3.15
Column (B) Testimony CSB
Column (C) = Column (A) + Column (B)

Tucson Electric Power
Docket No. E-01933A-22-0107
Test Year Ended December 31, 2021

RUCO Schedule 13
Witness: Michlik

SUMMARY OF OPERATING INCOME STATEMENT - ACC JURISDICTIONAL - ADJUSTED TEST YEAR AND RUCO

LINE NO.	Description	(A) COMPANY AS FILED	(B) RUCO TEST YEAR ADJUSTMENTS	(C) RUCO TEST YEAR AS ADJUSTED
1	**Operating Revenues**			
2	Electric Retail Non-Fuel Revenue	$ 736,474,603	$ -	$ 736,474,603
3	PPFAC Revenue	319,817,526		319,817,526
4	Sales for Resale	-		-
5	Other Operating Revenue	39,899,714		39,899,714
6	**Total Operating Revenues**	$ 1,096,191,843	$ -	$ 1,096,191,843
7				
8	**Operating Expenses**			-
9	Fuel, Purchased Power & Transmission	$ 319,817,526	$ -	$ 319,817,526
10	REST - Fuel & Purchased Power	65,124,072	-	65,124,072
11	Other Operations and Maintenance Expense	348,440,821	(13,339,527)	335,101,294
12	Depreciation and Amortization	225,533,111	(35,203,991)	190,329,120
13	Taxes Other than Income Taxes	59,576,379	(37,777)	59,538,602
14	Income Taxes	(23,184,003)	12,617,963	(10,566,040)
15	**Total Operating Expenses**	$ 995,307,906	$ (35,963,332)	$ 959,344,574
16	**Net Operating Income**	$ 100,883,938	$ 35,963,332	$ 136,847,270

References:
Column [A]: Company as Filed
Column [B]: RUCO Schedule 14
Column (C): Column (A) + Column (B)

OPERATING INCOME STATEMENT - ACC JURISDICTIONAL - ADJUSTED TEST YEAR AND RUCO RECOMMENDED ADJUSTMENTS

LINE NO.	Description	(A) COMPANY AS FILED	(B) Adj. 1 Payroll Expense RUCO-15	(C) Adj. 2 Payment Card Processing Fees RUCO-16	(D) Adj. 3 Board of Directors Fees RUCO-17	(E) Adj. 4 Short-Term Incentive Program RUCO-18	(F) Adj. 5 Long-Term Incentive Program RUCO-19	(G) Adj. 6 SERP Expense RUCO-20
	Operating Revenue							
1	Electric Retail Non-Fuel Revenue	$ 736,474,603	$ -	$ -	$ -	$ -	$ -	$ -
2	PPFAC Revenue	319,817,526						
3	Sales for Resale	-						
	Other Operating Revenue	39,899,714						
4	**Operating Margin**	$ 1,096,191,843	$ -	$ -	$ -	$ -	$ -	$ -
5								
6	**Operating Expenses**							
7	Fuel, Purchased Power & Transmission	$ 319,817,526	$ -	$ -	$ -	$ -	$ -	$ -
8	REST - Fuel & Purchased Power	65,124,072	-	-	-	-	-	-
9	Other Operations and Maintenance Expense	348,440,821	-	(2,744,491)	(356,137)	(4,469,854)	(2,735,258)	(1,459,808)
10	Depreciation and Amortization	225,533,111	-	-	-	-	-	-
11	Taxes Other than Income Taxes	59,576,379	-	-	-	-	-	-
12	Income Taxes	(23,184,003)	-	-	-	-	-	-
13	**Total Operating Expenses**	$ 995,307,906	$ -	$ (2,744,491)	$ (356,137)	$ (4,469,854)	$ (2,735,258)	$ (1,459,808)
14	**Net Operating Income**	$ 100,883,938	$ -	$ 2,744,491	$ 356,137	$ 4,469,854	$ 2,735,258	$ 1,459,808

Tucson Electric Power
Docket No. E-01933A-22-0107
Test Year Ended December 31, 2021

OPERATING IN(OPERATING INCOME STATEMENT - ACC JURISDICTIONAL - ADJUSTED TEST YEAR AND RUCO RECOMMENDED ADJUSTMENTS

LINE NO.	Description	(H) Adj. 7 Severance Pay RUCO-21	(I) Adj. 8 Industry Dues RUCO-22	(J) Adj. 9 Other Dues RUCO-23	(K) Adj. 10 Depreciation Expense RUCO-24	(L) Adj. 11 Rate Case Expense RUCO-25	(M) Adj. 12 Interest Synchronization RUCO-26	(N) Adj. 13 Income Tax RUCO-27	(O) RUCO as Adjusted
	Operating Revenue								
1	Electric Retail Non-Fuel Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 736,474,603
2	PPFAC Revenue								319,817,526
3	Sales for Resale								-
	Other Operating Revenue								39,899,714
4	**Operating Margin**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,096,191,843
5									-
6	**Operating Expenses**								
7	Fuel, Purchased Power & Transmission	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 319,817,526
8	REST - Fuel & Purchased Power	-	-	-	-	-	-	-	65,124,072
9	Other Operations and Maintenance Expense	(869,618) a	(607,375)	(96,986)	-	-	-	-	335,101,294
10	Depreciation and Amortization	-	-	-	(35,203,991)	-	-	-	190,329,120
11	Taxes Other than Income Taxes	(37,777) b	-	-	-	-	-	-	59,538,602
12	Income Taxes	-	-	-	-	-	515,731	12,102,232	(10,566,040)
13	**Total Operating Expenses**	$ (907,395)	$ (607,375)	$ (96,986)	$ (35,203,991)	$ -	$ 515,731	$ 12,102,232	$ 959,344,574
14	**Net Operating Income**	$ 907,395	$ 607,375	$ 96,986	$ 35,203,991	$ -	$ (515,731)	$ (12,102,232)	$ 136,847,270

Tucson Electric Power
Docket No. E-01933A-22-0107
Test Year Ended December 31, 2021

RUCO Schedule 15
Witness: Michlik

OPERATING INCOME ADJUSTMENT NO. 1
PAYROLL EXPENSE

			(A)	(B)	(C)
Line No.	**FERC No.**	**DESCRIPTION**	**COMPANY PROPOSED**	**RUCO ADJUSTMENT**	**RUCO AS ADJUSTED**
1	Various	Non-Union Payroll Expense	$ -	$ -	$ -

References:
Column (A) = Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

Tucson Electric Power
Docket No. E-01933A-22-0107
Test Year Ended December 31, 2021

RUCO Schedule 16
Witness: Michlik

OPERATING INCOME ADJUSTMENT NO. 2
REVERSE PAYMENENT CARD PROCESSING FEES

			(A)	(B)	(C)
Line No.	**FERC No.**	**DESCRIPTION**	**COMPANY PROPOSED**	**RUCO ADJUSTMENT**	**RUCO AS ADJUSTED**
1	903	Customer Records & Collection Expenses	$ 2,744,491	$ (2,744,491)	$ -

Source: RUCO data request 9.02(a) and (g).

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

Tucson Electric Power
Docket No. E-01933A-22-0107
Test Year Ended December 31, 2021

RUCO Schedule 17
Witness: Michlik

OPERATING INCOME ADJUSTMENT NO. 3
DIRECTORS AND OFFICERS (D&O) INSURANCE EXPENSE

			(A)	(B)	(C)
Line No.	FERC No.	DESCRIPTION	COMPANY PROPOSED	RUCO ADJUSTMENT	RUCO AS ADJUSTED
1	930.2	Board of Directors Fees	$ 712,273	$ (356,137)	$ 356,137

Source: RUCO data request 1.46 and 4.06

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

Tucson Electric Power
Docket No. E-01933A-22-0107
Test Year Ended December 31, 2021

RUCO Schedule 18
Witness: Michlik

OPERATING INCOME ADJUSTMENT NO. 4
SHORT-TERM INCENTIVE PROGRAM

Line No.	FERC No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED	(D) ACC JURISDICTIONALLY ADJUSTED
1	Various	PEP Expense	$ 10,724,060	$ (5,362,030)	$ 5,362,030	$ 4,469,854

Line No.	FERC	Three-Year Average	1/2 of 3 Year Average	ACC Jurisdictional Amount
2				
3	RUCO's Calculation:			
4		Three-Year	1/2 of 3 Year	ACC
5	FERC	Average	Average	Jurisdictional Amount
6				
7	Non-Executive			
8	0506	$ 1,772,241	$ 886,120	$ 799,458
9	0514	746,908	373,454	336,930
10	0566	699,065	349,532	31,776
11	0570	102,266	51,133	4,648
12	0588	676,607	338,303	338,303
13	0598	142,418	71,209	71,209
14	0903	448,152	224,076	224,076
15	0920	4,673,119	2,336,559	2,019,722
16	Subtotal	$ 9,260,775	$ 4,630,387	$ 3,826,123
17				
18	0408			
19				
20	Executive			
21	0500	$ 166,666	$ 83,333	$ 72,033
22	0566	-	-	$ -
23	0588	166,666	83,333	$ 83,333
24	0920	1,129,953	564,977	$ 488,366
25	Subtotal	$ 1,463,285	$ 731,642	$ 643,732
26				
27				
28				
29	Totals	$ 10,724,060	$ 5,362,030	$ 4,469,854

Source: UDR 1.016c AND RUCO data request 6.1

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

Tucson Electric Power
Docket No. E-01933A-22-0107
Test Year Ended December 31, 2021

RUCO Schedule 19
Witness: Michlik

OPERATING INCOME ADJUSTMENT NO. 5
LONG-TERM INCENTIVE ("LTI") COMPENSATION PROGRAM

			(A)	(B)	(C)
Line No.	**FERC No.**	**DESCRIPTION**	**COMPANY PROPOSED**	**RUCO ADJUSTMENT**	**RUCO AS ADJUSTED**
1	920	LTI Compensation Program	$ 2,735,258	$ (2,735,258)	$ -

Source: UDR 1.016c AND RUCO data request 6.2

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

Tucson Electric Power
Docket No. E-01933A-22-0107
Test Year Ended December 31, 2021

RUCO Schedule 20
Witness: Michlik

OPERATING INCOME ADJUSTMENT NO. 6
SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN ("SERP") EXPENSE

Line No.	FERC No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	926	SERP Expense	$ 1,459,808	$ (1,459,808)	$ -

Source: UDR 1.016c AND RUCO data request 6.3

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

Tucson Electric Power
Docket No. E-01933A-22-0107
Test Year Ended December 31, 2021

RUCO Schedule 21
Witness: Michlik

OPERATING INCOME ADJUSTMENT NO. 7
SEVERANCE PAY

			(A)	(B)	(C)
Line No.	**FERC No.**	**DESCRIPTION**	**COMPANY PROPOSED**	**RUCO ADJUSTMENT**	**RUCO AS ADJUSTED**
1	920	Severance Pay	$ 869,618	$ (869,618)	$ -
2	408	Payroll	37,777	(37,777)	-
3		Total	$ 907,395	$ (907,395)	$ -

Source: UDR ECB 1.020 and RUCO data request 4.07.

References:
Column (A) Per Company Filing
Column (B) Testimony JMM
Column (C) = Column (A) + Column (B)

Tucson Electric Power
Docket No. E-01933A-22-0107
Test Year Ended December 31, 2021

RUCO Schedule 22
Witness: Michlik

OPERATING INCOME ADJUSTMENT NO. 8
INDUSTRY MEMBERSHIP DUES

Line No.	DESCRIPTION	(A) TEST YEAR AMOUNT	(B) LOBBYING PERCENTAGE	(C) AMOUNT EXCLUDED BY COMPANY	(D) AMOUNT AFTER DEDUCTION	(E) RUCO AS ADJUSTED	(F) ACC JURISDICTIONALLY ADJUSTED
1	**Industry Dues**						
2	Baker Botts LLP	$ 73,350	0.00%	$ -	$ 73,350	$ 36,675	$ 31,703
3	West Associates	27,246	10.00%	2,725	24,521	12,261	10,599
4	EEI Membership	636,169	14.30%	90,972	545,197	272,598	235,645
5	EEI USWAG	30,985	0.80%	248	30,737	15,369	13,285
6	EEI Industry Issues	55,561	27.30%	15,168	40,393	20,196	17,459
7	EEI Restoration, Operations & Crisis Mgmt	10,000	0.00%	-	10,000	5,000	4,322
8	APLIC	2,500	0.00%	-	2,500	1,250	1,081
9	Electric Power Research Institute ("EPRI")	678,547	0.00%	-	678,547	339,274	293,282
10	Total Industry Dues	$ 1,514,358		109,113	$ 1,405,245	$ 702,623	$ 607,375

Source: Company Pro-forma Membership Dues and Other Excludable Items

References:
Column (A) = Per Company Filing
Column (B) = Allocation Percentage
Column (C) = Column (A) * Column (B)
Column (D) = Column (A) - Column (C)
Column (E) = RUCO Testimony
Column (F) = Column (E) * .8644

Tucson Electric Power
Docket No. E-01933A-22-0107
Test Year Ended December 31, 2021

RUCO Schedule 23
Witness: Michlik

REDACTED
OPERATING INCOME ADJUSTMENT NO. 9
OTHER MEMBERSHIP DUES

Line No.	DESCRIPTION	(A) TEST YEAR AMOUNT	(B) PERCENTAGE ALLOCATED TO ARIZONA	(C) COMPANY PROPOSED	(D) RUCO ADJUSTMENT	(E) RUCO AS ADJUSTED
1	Other Dues					
3	[redacted]					
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22	Total Other Dues	$ 114,592		$ 96,986	$ (96,986)	$ -

Source: Company Pro-forma Membership Dues and Other Excludable Items

References:
Column (A) = Per Company Filing
Column (B) = Allocation Percentage
Column (C) = Column (A) * Column (B)
Column (D) = Testimony JMM
Column (E) = Column (C) + Column (D)

OPERATING INCOME ADJUSTMENT NO. 10
DEPRECIATION EXPENSE

Line No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) ADJUSTMENT	(C) RUCO AS ADJUSTED	
1	Depreciation & Amortization Expense	$ 219,485,406	$ -	$ 219,485,406	
2	DSM Regulatory Asset Amortization Expense	6,047,705	-	6,047,705	
3	Total	$ 225,533,111	$ -	$ 225,533,111	
4	To Remove Annual Depr Expense Related to Routine Office Furniture	-	(34,719)	(34,719)	From Line 17
5	To Remove Annual Depr Expense Related to PTY Plant Retirements	-	(35,169,272)	(35,169,272)	From Line 24
6	Total	$ 225,533,111	$ (35,203,991)	$ 190,329,120	
7					
8					
9					
10					
11		Calculation of Annual			
12		Depreciation Expense			
13		Related to PTY Office Furniture			
14	PTY Office Furniture	$ 830,608	RUCO Sch 8; RUCO Data Request 1.41		
15	Multipled by Depreciation Rate	4.18%	From Depreciation Study		
16	Annual Depr Expense for PTY Office Furniture	$ 34,719			
17					
18					
19		Calculation of Annual			
20		Depreciation Expense			
21		Related to PTY Plant Retirements			
22	PTY Retirements Depreciation for 6 months	$ 17,584,636	RUCO Data Request 1.37		
23	Multipled by	2	To reflect 12 months of Depreciation Expense		
24	Annual Depr Expense for PTY Retirements	$ 35,169,272			

References:
Column (A) = Per Company Filing, Schedule C-1, Page 1
Column (B) = Column (C) - Column (A)
Column (C) = Column B + Column C

Tucson Electric Power
Docket No. E-01933A-22-0107
Test Year Ended December 31, 2021

RUCO Schedule 25
Witness: Erdwurm

OPERATING INCOME ADJUSTMENT NO. 11
RATE CASE EXPENSE

Line No.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Annual Rate Case Expense		$ -	$ -

Note: See the Direct Testimony of RUCO Wintess Bentley Erdwurm.

References:
Column (A) Per Company Filing
Column (B) Testimony DBE
Column (C) = Column (A) + Column (B)

Tucson Electric Power
Docket No. E-01933A-22-0107
Test Year Ended December 31, 2021

RUCO Schedule 26
Witness: Michlik

OPERATING INCOME ADJUSTMENT NO. 12
INTEREST SYNCHRONIZATION

Line No.	Description	Tax Rate	(A) Company Proposed	(B) RUCO Recommended
1	Adjusted Rate Base		$ 3,625,147,888	$ 3,502,488,686
2	Weighted Cost of Debt		1.75%	1.75%
3	Synchronized Interest Deduction		$ 63,272,244	$ 61,131,387
4	Increase (Decrease) in Deductible Interest			$ (2,140,857)
5	State Income Taxes	3.91%		$ 83,735
6	Federal Taxable Income			$ (2,057,122)
7	Federal Income Taxes	21.00%		$ 431,996
8	Increase (Decrease) to Income Tax Expense			$ 515,731

References:
Column (A) Per Company Filing
Column (B) Testimony JMM

Tucson Electric Power
Docket No. E-01933A-22-0107
Test Year Ended December 31, 2021

RUCO Schedule 27
Witness: Michlik

OPERATING INCOME ADJUSTMENT NO. 13
INCOME TAX EXPENSE

Line No.	RUCO Income Tax Calculation on RUCO Adjustments (Thousands of Dollars)		
1	Operating Revenue	$	-
2	Electric Retail Non-Fuel Revenue		-
3	PPFAC Revenue		-
4	Sales for Resale		-
5	Other Operating Revenue		-
6	Operating Margin	$	-
4			
5	Operating Expenses		
6	Fuel, Purchased Power & Transmission	$	-
7	REST - Fuel & Purchased Power	$	-
8	Other Operations and Maintenance Expense	$	(13,339,527)
9	Depreciation and Amortization	$	(35,203,991)
10	Taxes Other than Income Taxes	$	(37,777)
12	Pre -Tax Operating Expenses	$	(48,581,295)
13	Pre -Tax Operating Income	$	48,581,295
14	Income Taxes	$	12,102,232
15			
16	Combined Effective Tax Rate		24.9113%

References:
Testimony JMM

TUCSON ELECTRIC POWER COMPANY

DOCKET NO. E-01933A-22-0107

REDACTED
DIRECT TESTIMONY
OF
CRYSTAL S. BROWN

ON BEHALF OF THE
RESIDENTIAL UTILITY CONSUMER OFFICE

JANUARY 11, 2023

TABLE OF CONTENTS

Page

I. INTRODUCTION ... 1

II. BACKGROUND ... 2

III. SUMMARY OF RUCO'S RECOMMENDED RATE BASE AND OPERATING INCOME ADJUSTMENTS ... 3

RUCO Operating Income Adjustments ... 4

IV. RATE BASE ... 4

Rate Base Summary ... 5
Rate Base Adjustment No. 1 – Routine Post Test Year Plant, Office Furniture ... 6
Tools that Mitigate the Regulatory Lag on the PTY Office Furniture ... 6
PTY Office Furniture is Not an Entitlement ... 7
Percentage of the PTY Office Furniture to the Total Amount of PTY Plant ... 8
Rate Base Adjustment No. 2 – PTY Plant Retirements ... 9
Rate Base Adjustment No. 3 – Accumulated Depreciation ... 10
Reason for PTY Plant--to Address "Regulatory Lag" ... 11
Regulatory Lag Provides Both Benefits and Disadvantages for the Company ... 11
Rate Base Adjustment No. 4 – Cash Working Capital ... 13
Amortized Portion of Property Insurance and Injuries & Damages Prepaid Expense ... 15
Pension Expense ... 16
Expense Lag Days for Property Taxes ... 18
Interest Expense on Customer Deposits ... 19
Interest Expense on Long-Term Debt ... 19
Rate Base Adjustment No. 5 – Regulatory Assets and Related Accumulated Deferred Income Taxes ("ADIT") Adjustment ... 20

V. OPERATING INCOME ... 21

Operating Income Adjustment No. 10 – Depreciation and Amortization Expense ... 21

ATTACHMENTS

RUCO Data Request No. 3.06 ... Attachment 1
REDACTED Company Data Request UDR WKC-1.001 ... Attachment 2
REDACTED RUCO Data Request No. 8.01 ... Attachment 3
REDACTED Company Data Reques UDR ECB 1.015 ... Attachment 4
RUCO Data Request No. 3.09 ... Attachment 5
REDACTED RUCO Data Request No. 3.10 ... Attachment 6

SCHEDULES

The Schedules for Ms. Brown's Testimony are attached to Mr. Michlik's Direct Testimony

EXECUTIVE SUMMARY

Tucson Electric Power Company ("TEP or Company") is a for-profit, certificated Arizona public service corporation that provides electric utility service to various communities in Pima County, Arizona. On June 17, 2022, TEP filed an application with the Arizona Corporation Commission ("Commission") for a permanent rate increase. TEP serves more than 438,000 customers in and around Pima County, Arizona. TEP's corporate business office is located at 88 East Broadway Blvd., Tucson, AZ 85702.

The direct testimony of Crystal S. Brown presents RUCO's recommendations in the areas of rate base and depreciation and amortization expense. RUCO's adjustments to the Company's OCRB resulted in a net decrease of $122,659,202, from $3,625,147,888 to $3,502,488,686. The decrease was primarily due to adjustments made to the following:

- <u>Routine Post-Test Year Plant</u> – RUCO recommends decreasing Original Cost Rate Base ("OCRB") plant in service by $830,608 to remove PTY plant that is routine in nature such as office furniture.

- <u>PTY Retirements</u> – RUCO recommends decreasing OCRB plant in service by $89,954,490 to remove PTY retirements.

- <u>Accumulated Depreciation</u> – RUCO recommends increasing OCRB accumulated depreciation by $3,200,812 to reflect the regulatory lag on accumulated depreciation and to remove accumulated depreciation and amortization related to RUCO's plant and regulatory asset adjustments.

- <u>Cash Working Capital</u> – RUCO recommends decreasing cash working capital by $1,005,564 to reflect RUCO's recommended operating expenses and expense lag days in its cash working capital calculation.

- <u>Regulatory Assets and Related Accumulated Deferred Income Tax ("ADIT") Adjustment</u> – RUCO recommends decreasing the regulatory assets by $35,392,313 to remove the Company's proposed regulatory assets and to increase the ADIT balance by $7,724,585 to remove the related ADIT adjustment.

- <u>Depreciation and Amortization Expense</u> – This adjustment decreases operating expense by $35,203,991 to reflect RUCO's recommended plant and deferred regulatory asset balances.

The Direct Testimony of Jeffrey Michlik presents RUCO's recommendations on revenue requirement and all operating expenses except depreciation expense and those covered by other RUCO witnesses as noted. Mr. Bentley Erdwurm presents RUCO's recommendations on rate case expense, rate design, the Company's proposed regulatory assets and its current and proposed adjustor mechanisms. Mr. John Cassidy is presenting RUCO's cost of capital recommendations.

I. INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Crystal S. Brown. I am a Public Utilities Analyst V employed by the Residential Utility Consumer Office ("RUCO"). My business address is 1110 West Washington Street, Suite 220, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities and capacity as a Public Utilities Analyst V.

A. I am responsible for analyzing and examining accounting, financial, statistical and other information. I prepare reports based on my analyses that present RUCO's recommendations to the Arizona Corporation Commission ("Commission" or "ACC") on utility revenue requirements, rate design and other matters in the interests of fair and reasonable rates for residential utility ratepayers. I also provide expert testimony on these same matters.

Q. Please state your educational background and qualifications in the utility regulatory field.

A. I earned a Bachelor of Science Degree in Business Administration from the University of Arizona and a Bachelor of Science Degree in Accounting from Arizona State University.

I have been employed by RUCO as a Public Utilities Analyst V since June 2019. Prior to joining RUCO, I was employed by the Commission for over 20 years and advanced through all of the Public Utilities Analyst positions. My last position held was as an Executive Consultant III. Prior to joining the Commission, I was employed by the Department of Revenue as a Senior Internal Auditor and by the Office of the Auditor General as a Financial Auditor. I was a Cost Center Review Specialist for Blue Cross Blue Shield of Arizona prior to my employment in state government.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to present RUCO's recommendations regarding Tucson Electric Power Company's ("Tucson Electric," "TEP," or "Company") permanent rate application filed on June 17, 2022.

Q. What is the scope of your testimony in this case?

A. I am presenting testimony and schedules addressing rate base and depreciation and amortization expense adjustments. Mr. Jeffrey Michlik is presenting RUCO's recommendations on revenue requirement and all operating expenses except depreciation expense and those covered by other RUCO witnesses as noted. Mr. Bentley Erdwurm presents RUCO's recommendations on rate case expense, rate design, the Company's proposed regulatory assets and its current and proposed adjustor mechanisms. Mr. John Cassidy is presenting RUCO's cost of capital recommendations.

Q. What is the basis of your testimony in this case?

A. I performed a regulatory audit of the Company's application to determine whether sufficient, relevant, and reliable evidence exists to support the Company's requested rate increase. The regulatory audit consisted of examining and testing the financial information, accounting records, and other supporting documentation and verifying that the accounting principles applied were in accordance with the Commission adopted Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts ("USOA").

II. BACKGROUND

Q. Please provide a brief background as it relates to this Application.

A. TEP is an Arizona "C" Corporation. TEP is a for-profit, certificated Arizona public service corporation that provides electric utility service to various communities in Pima County, Arizona. On June 17,2022, TEP filed an application with the Commission for a permanent rate increase. TEP serves more than 438,000 customers in and around Pima County, Arizona. TEP's corporate business office is located at 88 East Broadway Blvd., Tucson, AZ 85702.

Q. What test year did the Company use in this filing?

A. The Company's rate filing is based on the twelve months ended December 31, 2021 ("TY").

III. SUMMARY OF RUCO'S RECOMMENDED RATE BASE AND OPERATING INCOME ADJUSTMENTS

Q. Please summarize the rate base adjustments addressed in your testimony.

A. My testimony addresses the following rate base issues:

Rate Base Adjustments

Rate Base Adjustment No. 1 – Routine Post-Test Year Plant – This adjustment removes PTY plant that is routine in nature, such as office furniture. This adjustment decreases OCRB plant in service by $830,608.

Rate Base Adjustment No. 2 – Post-Test Year Plant Retirements – This adjustment removes PTY plant retirements. This adjustment decreases OCRB plant in service by $89,954,490. It also decreases accumulated depreciation by the same amount.

Rate Base Adjustment No. 3 – Accumulated Depreciation – This adjustment increases accumulated depreciation by $3,200,812 to reflect the regulatory lag on accumulated depreciation and to remove accumulated depreciation and amortization related to RUCO's plant and regulatory asset adjustments.

Rate Base Adjustment No. 4 – Cash Working Capital – This adjustment decreases cash working capital to reflect RUCO's recommended operating expenses and expense lag days in its cash working capital calculation. This adjustment decreases cash working capital by $1,005,564.

Rate Base Adjustment No. 5 - Regulatory Assets and Related Accumulated Deferred Income Tax ("ADIT") Adjustment – RUCO recommends decreasing the regulatory assets by $35,392,313 to remove the Company's proposed regulatory assets and to increase the ADIT balance by $7,724,585 to remove the related ADIT adjustment.

RUCO Operating Income Adjustments

Q. Please summarize the operating income recommendations and adjustments addressed in your testimony.

A. My testimony addresses Operating Income Adjustment No. 10, Depreciation Expense. All other revenue and expense adjustments are discussed in the testimony of RUCO witness, Jeffrey Michlik or other RUCO witnesses as noted.

Operating Income Adjustment No. 10 – Depreciation and Amortization Expense – This adjustment decreases depreciation and amortization expense to reflect RUCO's recommended plant and deferred regulatory asset balances and amortization period. This adjustment decreases depreciation and amortization expense by $35,203,991.

IV. RATE BASE

Q. Did the Company treat its Original Cost Rate Base ("OCRB") as its Fair Value Rate Base ("FVRB")?

A. No.

Q. How did the Company calculate its FVRB?

A. The Company calculated its FVRB as the simple average (arithmetic mean) of the OCRB and the Reconstruction Cost New Less Depreciation ("RCND") Rate Base. This methodology has been consistently accepted by the Commission in prior rate cases.

Rate Base Summary

Q. Please summarize RUCO's adjustments to the Company's OCRB.

A. RUCO's adjustments to the Company's OCRB resulted in a net decrease of $122,659,202, from $3,625,147,888 to $3,502,488,686. The decrease was primarily due to adjustments made to the following: (1) Routine Post-Test Year Plant, (2) Post-Test Year Retirements, (3) Accumulated Depreciation, (4) Cash Working Capital, and (5) the Proposed Regulatory Assets and Related ADIT adjustment as shown on RUCO Schedule 4 and Schedule 5.

Q. Please summarize RUCO's adjustments to the Company's RCND rate base.

A. RUCO's adjustments to the Company's RCND resulted in a net decrease of $233,362,764, from $6,875,990,093 to $6,642,627,329. RUCO's adjustments to the Company's RCND rate base resulted in a net decrease of as shown on RUCO Schedules 6 and 7.

Q. For those RUCO adjustments that affect not only the OCRB but also RCND, has RUCO also presented this information?

A. Yes, if an adjustment affects not only the OCRB, but also the RCND rate base, RUCO has shown the effects on the same schedule.

Q. How does RUCO make its used and useful determination for plant?

A. RUCO relies, in large part, on Staff's engineering witness and data request responses from the Company.

Rate Base Adjustment No. 1 – Routine Post Test Year Plant, Office Furniture

Q. What amount did RUCO remove for routine PTY plant?

A. The Company added $830,608 in PTY office furniture in order to mitigate the regulatory lag related to the PTY office furniture. RUCO removed the $830,608 in PTY office furniture.

Tools that Mitigate the Regulatory Lag on the PTY Office Furniture

Q. Are there other tools, in addition to PTY plant, that a company can utilize to mitigate regulatory lag?

A. Yes. The Commission has provided numerous tools to help companies manage regulatory lag. Those tools include, but are not limited to, accounting deferrals/regulatory assets, PTY expense adjustments, purchased power adjustors, and various types of surcharge mechanisms.[1] Each of these tools provide for recovery of some or all of a particular cost, or for the recovery of what would have otherwise been reduced revenue between utility rate cases.

For example, a regulatory asset is an expense item that a company can include in rate base and earn a rate of return and recover through depreciation expense. This treatment guarantees a 100% recovery of the cost and serves to mitigate the Company's regulatory lag regarding its authorized rate of return. TEP has several Commission-approved regulatory assets. As shown in the table below, the Company receives recovery of an additional $7,490,469 in operating expenses from what would have otherwise been reduced revenue between utility rate cases. When the return of $2,428,613 on the $33 million in regulatory assets is reflected, the total grows to over $9.9 million per year.

[1] These ratemaking tools can be used once approved by the Commission.

	Regulatory Assets		
Description	**Amount Included in Rate Base**	**Amount Included in Operating Expense**	**Total Cash from Regulatory Assets**
Springerville Unit 1 Leasehold Improvement Costs	$ 4,151,362	$2,388,651	
Navajo Abandon Plant Reg Asset NBV	$29,329,090	$4,159,015	
Sundt U1 and U2 Cost of Removal	$ (257,299)	$ 942,803	
	$33,223,154	**$7,490,469**	$7,490,469
Multiplied by Co. Proposed Rate of Return	x 7.31%		
	$2,428,613		$2,428,613
Additional Cash to Mitigate Regulatory Lag -->			**$9,919,082**

Additionally, the Company has an approved fuel adjustor which guarantees recovery of 100% of its fuel costs which further mitigates its regulatory lag related to its authorized rate of return.

PTY Office Furniture is Not an Entitlement

Q. Is a company's proposal to include any and all PTY plant an automatic entitlement that it will receive all of the PTY plant it has proposed?

A. No, it is not. The Commission's decision in EPCOR's relatively recent wastewater case has put utilities on notice that there should not be an automatic expectation that PTY plant will be approved in future cases unless circumstances warrant its inclusion:

> Although the Commission agrees with the inclusion of the PTY plant set forth in the Agreement, based in large part because the Commission required EPCOR to file this rate case, ***EPCOR is put on notice that going forward there should not be an expectation that PTY plant will be approved in future rate cases unless there are circumstances that would warrant its inclusion***.[2] (Emphasis Added).

[2] Decision No.76162 at 71.

Q. Has the Commission identified criteria regarding PTY plant?

A. Yes. One of the main criteria that the Commission has identified is that the PTY plant must be large in comparison to rate base "such that not including the post test-year plant in the cost of service would jeopardize the utility's financial health." The Commission, in Decision No. 71410, identified the following criteria for inclusion of PTY plant:

> Staff states that it has traditionally recognized two scenarios in which Staff believes recognition of post test-year plant is appropriate: **(1) when the magnitude of the investment relative to the utility's total investment is such that not including, the post test-year plant in the cost of service would jeopardize the utility's financial health,** and (2) when certain conditions exist as follows: (a) the cost of the post test-year plant is significant and substantial, (b) the net impact on revenue and expenses for the post test-year plant is known and insignificant or is revenue neutral, and (c) the post test-year plant is prudent and necessary for the provision of services and reflects appropriate, efficient, effective, and timely decision-making.[3] (Emphasis added).

Percentage of the PTY Office Furniture to the Total Amount of PTY Plant

Q. What is the total amount of PTY plant that RUCO has recommended for TEP?

A. Of the $209 million in PTY plant that TEP has requested, RUCO has recommended approval of $208,169,392, a difference of $830,608. The $830,608 is the PTY office furniture that RUCO is recommending that the Company recover in its next rate case.

Q. What is the percentage of the Office Furniture compared to the total PTY plant?

A. The table below shows that the $830,608 in PTY office furniture represents less than 1% (i.e., 0.39%) of the total $208,169,392 in PTY plant. Consequently, the $830,608 is not significant compared to the total PTY plant and total rate base.

[3] Footnotes excluded – footnotes referenced testimony to support decision.

Percentage of PTY Office Furnitre to Total PTY Plant		
	PTY Plant	% of Total
All PTY Plant Except Office Furniture	$208,169,392	99.61%
PTY Office Furniture	$ 830,608	**00.39%**
Total	$209,000,000	100.00%

Q. Would the Company be placed in financial jeopardy or provide inadequate service if the costs of the old office furniture continued to be used until the next rate case?

A. No, recovering the routine PTY plant in the next rate case would not place the Company in financial jeopardy or cause it to provide inadequate service as the amount is small in comparison to total rate base.

Q. What is RUCO's recommendation?

A. RUCO recommends decreasing OCRB by $830,608 as shown on RUCO Schedules 5 and 8.

Rate Base Adjustment No. 2 – PTY Plant Retirements

Q. Did the Company remove any retirements related to PTY plant after the Test Year?

A. No.

Q. Do plant retirements impact depreciation expense?

A. Yes. Depreciation expense is calculated based on plant that is actually in service. The FERC Uniform System of Accounts requires plant that is no longer in service be removed from the appropriate plant accounts. If the plant retirements are not removed, then depreciation expense will be overstated and the Company is unjustly enriched by the amount of plant which it did not remove from its plant accounts.

Q. Should ratepayers continue to pay a return on plant, and depreciation expense for non-existent assets?

A. No, they should not.

Q. Did RUCO remove retirements related to PTY plant?

A. Yes, RUCO removed retirements related to PTY plant based on the Company's response to RUCO Data Request 1.37.

Q. What is RUCO's recommendation?

A. RUCO recommends decreasing OCRB plant in service by $89,954,490 to reflect plant retirements. RUCO also recommends decreasing accumulated depreciation by the same amount as shown on RUCO Schedules 5, 9, and 10.

Rate Base Adjustment No. 3 – Accumulated Depreciation

Q. What is the Company proposing for accumulated depreciation?

A. The Company is proposing $2,263,682,182 as shown on RUCO Schedule 5.

Q. Did RUCO make any adjustments?

A. Yes, RUCO *decreased* accumulated depreciation and amortization to reflect RUCO's plant and regulatory asset adjustments as shown on RUCO Schedule 10. The total of the adjustments shown on lines 4 through 8 of Schedule 10 reduce accumulated depreciation by $91,963,748.

Q. Did RUCO make any other adjustments?

A. Yes. RUCO *increased* accumulated depreciation by adding six months of Test Year depreciation expense (i.e., $95,164,560) to the accumulated depreciation balance in order to reflect the regulatory lag for accumulated depreciation. The adjustment is shown on RUCO Schedule 10, lines 3 and 15.

<u>Reason for PTY Plant--to Address "Regulatory Lag"</u>

Q. Would you please provide an historical overview of PTY plant?

A. The Commission has traditionally used historical test years for the purposes of establishing utility revenue requirements in base rate cases. There is a period from the end of the test year until the date upon which new base rates will become effective that is generally referred to as "regulatory lag." Providing a means of recognizing significant changes in the utility's net investment in rate base that can be verified in the rate case can thus be one regulatory method to balance the interests of the utility and its customers.

Regulatory lag is measured using rate base[4]. The largest component of rate base is typically net plant. The components of net plant are (1) gross plant and (2) accumulated depreciation. The regulatory lag related to accumulated depreciation benefits the company whereas the regulatory lag related to gross revenue neutral plant is typically a financial disadvantage for the company.

<u>Regulatory Lag Provides Both Benefits and Disadvantages for the Company</u>

Q. How does the Regulatory Lag on gross "revenue neutral" PTY plant create a disadvantage for the Company?

A. The regulatory lag for gross PTY plant that is for customer growth will be offset by the revenues from the new customers and will generally allow the Company to earn its authorized rate of return. However, this is typically not the case for significant amounts of *"revenue neutral"* gross PTY plant. Consequently, the regulatory lag related to *"revenue*

[4] This is because shareholders are only allowed to earn a return on their net investment in the utility (i.e., rate base).

neutral" gross plant works *against* the company because any increases in revenues are typically insufficient to offset the increases in cost (i.e., recovery of depreciation expense and return on investment) of the *"revenue neutral"* gross PTY plant.

Q. How does the Regulatory Lag on accumulated depreciation provide a financial benefit for the Company?

A. Accumulated depreciation is the amount of plant that customers have paid back to the shareholders through rates and a delay in recognizing the growth in accumulated depreciation that has occurred after the test year works to the company's advantage because it allows the Company to charge higher rates than it would otherwise charge during the same time period.

For example, when the growth in the accumulated depreciation balance after the test year is significant, it will result in a company needing less revenue to earn its authorized rate of return. This is because accumulated depreciation reduces rate base which, in turn, reduces the amount of operating income it needs in order to earn its authorized rate of return. Further, during the same time frame the company has built and installed its PTY plant, customers have already paid depreciation expense on all test year plant to the same date as the PTY plant. Customers may have to wait years or until the company decides to file another rate case to receive the financial benefit of lowered rates that the PTY accumulated depreciation provides.

Q. Does Arizona Public Service Company ("APS") reflect the regulatory lag on both components of PTY net plant?

A. Yes. APS, Arizona's largest investor owned electric utility, mitigates its regulatory lag by reflecting both components of PTY net plant (i.e., gross plant and accumulated depreciation). APS recognizes the increase that has occurred after the test year on accumulated depreciation to the same cut-off date as the PTY plant that it recommends. APS's methodology is balanced and results in the fairest rates to customers. Thus, when TEP does not reflect the PTY accumulated depreciation while simultaneously recognizing PTY plant, it is able to charge significantly higher rates than if it used the APS methodology. This financial benefit is real and works to TEP's advantage and unfairly disadvantages ratepayers.

Q. Does RUCO recommend that the same cutoff date used to reflect the regulatory lag on PTY plant be used to reflect the regulatory lag on PTY accumulated depreciation?

A. Yes, RUCO recommends that the same June 30, 2022 cut-off date that the Company has proposed for PTY plant be used to reflect the regulatory lag for PTY depreciation.

Q. What is RUCO's overall recommendation concerning accumulated depreciation?

A. RUCO recommends increasing accumulated depreciation by $3,200,812 as shown on RUCO Schedules 5 and 10.

Rate Base Adjustment No. 4 – Cash Working Capital

Q. In simple terms, what is the purpose of the cash working capital analysis in the determination of rate base?

A. The rate base measures the shareholder's net investment in the utility. Part of that investment is the *actual amount of cash* that the shareholders must pay during the year to bridge the gap between the payment of expenses and the receipt of revenues. The Company receives cash from customers' payments that the Company uses to meet and pay its operating expenses. However, the Company may sometimes not receive enough cash receipts from customers to pay expenses in a timely manner. When this situation occurs, the Company must provide the cash capital to pay the expenses. The amount of *actual cash* capital the Company pays *during the Test Year* is quantified in a lead-lag study. The amount of cash that the Company must provide in advance of customer cash receipts to pay expenses related to providing service is added to rate base where the Company will earn a return on that cash capital.

Cash working capital can be a negative amount. A negative cash working capital indicates that customers, on average, are providing cash in advance of the dates that the Company has to pay expenses. While the Company has possession of these funds, they are a source of cost-free cash capital that the Company can use for any purpose until making payments. Thus, the customer supplied cash capital is reflected as a decrease to rate base.

Q. What amount is TEP proposing for cash working capital?

A. The Company is proposing working capital of ($9,930,742) as shown on RUCO Schedule 11, page 1.

Q. Did RUCO make any adjustments?

A. Yes. RUCO reflected RUCO's recommended operating expenses, calculated lag days for pension expense and utilized the lag days in the cash working capital calculation, increased the expense lag days for property taxes and interest expenses, and removed prepayments expense from the cash working capital calculation.

Amortized Portion of Property Insurance and Injuries & Damages Prepaid Expense

Q. Do the Property Insurance and Injuries & Damages expenses that the Company included in the lead-lag study represent an actual outlay of cash during the Test Year?

A. No, they do not represent an actual outlay of cash made during the Test Year. The Property Insurance and Injuries & Damages expenses that the Company has included in the lead-lag study represent the amortized portion of prepaid Property Insurance and Injuries & Damages costs that the Company paid before the Test Year per the Company's response to RUCO Data Request 3.06 (Attachment 1).

Q. What adjustment did RUCO make to Property Insurance and Injuries & Damages expenses included in the lead-lag study?

A. RUCO removed the amortized portion of the prepaid expenses from the cash working capital calculation.

Q. How will the amortized portion of the Property Insurance and Injuries & Damages prepaid expenses be recovered?

A. The amortized portion of the Property Insurance and Injuries & Damages prepaid expenses will be recovered in operating expenses and the unamortized balance will be recovered in rate base. The recovery of the prepayments is similar to the recovery of gross plant. The recovery of the Test Year depreciated amount of gross plant is recovered dollar for dollar in operating expense and the undepreciated balance is included in rate base and recovered through a rate of return.

Q. Why did RUCO remove the amortized portion of the Property Insurance and Injuries and Damages Prepaid Expense?

A. The Company has proposed zero lag days for amortized prepayments. Similar to depreciation expense, the amortized prepayments do not represent an actual outlay of cash by the Company during the Test Year and, therefore, is inappropriate to include in the *cash* working capital calculation.

Pension Expense

Q. Are the contribution payments that the Company makes to its pension plans cash expenses?

A. Yes.

BEGIN CONFIDENTIAL

[redacted]

[redacted]

[redacted]

[redacted]

[redacted] END CONFIDENTIAL

Expense Lag Days for Property Taxes

Q. What are expense leads or lags in simple terms?

A. In simple terms, an expense lead is the number of days before an operating expense is due that a company pays for that expense[5]. An expense lag is the number of days after an operating expense is due that a company pays for that expense[6].

Q. What adjustment did RUCO make to the expense lag days for Property Taxes?

A. The Company's proposed 206.82 lag days for property tax payments. RUCO used 212 lag days.

Q. Why did RUCO use 212 lag days?

A. The 212 days are the typical property tax lag days approved by the Commission. It represents the most balanced approach for customers and utilities. Since a company has discretion when it pays its property taxes and that discretion can affect the outcome of a lead-lag study, typically the property tax payment date used for ratemaking purposes will be the latest date possible that will not incur any type of penalty (e.g. a late payment penalty). For ease of discussion, I will use a calendar year to measure the lag days. The first half of 2021 property taxes become delinquent after **November 1, 2021** and the second half becomes delinquent after **May 1, 2022**. The lag days are calculated as follows:

Midpoint of 2021	Payment Date	Lag Days	
7/2/2021	11/1/2021	122.00	First Half Becomes Delinquent After Nov 1st
7/2/2021	5/1/2022	303.00	Second Half Becomes Delinquent After May 1st
		425.00	
	Divided by	2	
		212.50	Average Property Tax Lag Days

[5] Measured from the midpoint of service.
[6] Measured from the midpoint of service.

Interest Expense on Customer Deposits

Q. What adjustment did RUCO make to Interest on Customer Deposits?

A. The Company has proposed zero lag days for interest on customer deposits. RUCO increased the number of expense lag from 0 to 182.50.

Q. How did RUCO calculate the 182.50 lag days?

A. RUCO calculated the 182.50 expense lag days by assuming that the Company made one interest payment at the end of 12 months (i.e., on December 31st). The midpoint of the year is June 30th. The expense lag is measured from the midpoint to the payment date. The lag for the interest on customer deposit payment is found by measuring the number of days from the midpoint of the year (i.e., June 30th) to December 31st, which is 182.5 days (i.e., 365 days ÷ 2 billing periods = 182.5 days).

Interest Expense on Long-Term Debt

Q. What adjustment did RUCO make to Interest Expense on Long-Term Debt?

A. RUCO increased the lag days from 90.60 to 91.25 in order to reflect the latest payment date possible that will not incur any type of penalty (e.g. a late payment penalty).

Q. How did RUCO calculate the 91.25 expense lag days?

A. RUCO calculated the 91.25 expense lag days by assuming that the Company made one interest payment at the end of the first six months of the year on June 30th and another interest payment at the end of the last six months of the year on December 31st. The midpoint of the year is June 30th. The expense lag is measured from the midpoint to the payment date. Since the first payment is made on the same date as the midpoint of the year, the lag is 0 days. The lag for the second payment is found by measuring the number of days from the midpoint of the year (i.e., June 30th) to December 31st, which is 182.5 days (i.e., 365 days ÷ 2 billing periods = 182.5 days). Consequently, averaging the lag days for the two payments results in an average lag of 91.25 days [i.e. (0 days +182.5 days) ÷ 2 = 91.25 days] for interest expense.

Q. Did RUCO make any other adjustments?

A. Yes, RUCO reflected RUCO's recommended operating expenses as shown on RUCO Schedule 11, page 3 of 4.

Q. What is RUCO's recommendation concerning cash working capital?

A. RUCO recommends decreasing cash working capital by $1,005,564 as shown on RUCO Schedules 5 and 11.

Rate Base Adjustment No. 5 – Regulatory Assets and Related Accumulated Deferred Income Taxes ("ADIT") Adjustment

Q. What amount is TEP proposing for new regulatory assets and the related ADIT adjustment?

A. The Company is proposing $35,392,313 for new regulatory assets and $(7,724,585) for the related ADIT adjustment as shown on RUCO Schedule 5.

Q. Did RUCO make any adjustments?

A. Yes, RUCO removed the $35,392,313 for the new regulatory assets and $(7,724,585) for the related ADIT adjustment as shown on RUCO Schedules 5 and 12 consistent with RUCO's recommendation that these costs be reflected in a balancing account with no "return on" any portion of these expenditures and amortized and recovered over time through operating expenses as discussed by Mr. Bentley Erdwurm.

V. OPERATING INCOME

Operating Income Adjustment No. 10 – Depreciation and Amortization Expense

Q. What adjustment did RUCO make to depreciation and amortization expense?

A. For depreciation expense, RUCO removed the depreciation expense related to the post-test year plant routine plant and post-test year plant retirements.

Q. Does RUCO have any concerns about the 8-year depreciation recovery period for the Springerville plant?

A. No, RUCO does not have any concerns at this time.

Q. What is RUCO's recommendation?

A. RUCO recommends decreasing depreciation and amortization expense by $35,203,991, as shown on RUCO Schedules 13 and 24.

Q. Does your silence on any of the issues, matters, findings, or lack of adjustment to and for other ratemaking components addressed or not in your testimony of any of the witnesses for the Company constitute your acceptance of their positions on such issues, matters or findings in future rate proceedings?

A. No, it does not.

Q. Does this conclude your direct testimony?

A. Yes, it does.

ATTACHMENT 1

RUCO's Data Request No. 3.06

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO
RUCO's 3rd SET OF DATA REQUESTS –
2022 TUCSON ELECTRIC POWER RATE CASE
DOCKET NO. E-01933A-22-0107
September 19 , 2022

RUCO 3.06

Lead-Lag Study, "0" Expense Lag Days – Referring to Schedule B-5, page 3 of 3, please explain why the Company is proposing "0" expense lag days for Property Insurance, Injuries and Damages, and Interest on Customer Deposits.

RESPONSE:

TEP used "0" Expense Lag Days for Property Insurance and Injuries and Damages because these involve primarily prepayments, and the effects of prepayments are incorporated into rate base as a separate line item (Schedule B-5, page 1 of 3, Line 4). Similarly, because customer deposits are a separately stated reduction to rate base, no expense lag days were computed for interest on customer deposits.

RESPONDENT:

Rigo Ramirez

WITNESS:

Jason Rademacher

REDACTED

ATTACHMENT 2

Company Data Request UDR WKC-1.001

REDACTED

ATTACHMENT 3

RUCO Data Request No. 8.01

REDACTED

ATTACHMENT 4

Company Data Request UDR ECB-1.015

ATTACHMENT 5

RUCO Data Request No. 3.09

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO
RUCO's 3rd SET OF DATA REQUESTS –
2022 TUCSON ELECTRIC POWER RATE CASE
DOCKET NO. E-01933A-22-0107
September 19 , 2022

RUCO 3.09

Lead-Lag Study, Pension Expense and Post Retirement Benefits Other than Pensions ("PBOP") – Please state whether or not the Company includes Pension Expense and PBOP in its lead-lag study. If so, please state the expense lag days used for each.

RESPONSE:

Pension expense and Post-Retirement Benefits Other than Pensions are included in the lead-lag study. The expense lag days used for each expense is -4.76.

RESPONDENT:

Rigo Ramirez

WITNESS:

Jason Rademacher

REDACTED

ATTACHMENT 6

RUCO Data Request No. 3.10

TUCSON ELECTRIC POWER COMPANY

DOCKET NO. E-01933A-22-0107

DIRECT TESTIMONY
OF
BENTLEY ERDWURM

ON BEHALF OF THE
RESIDENTIAL UTILITY CONSUMER OFFICE

JANUARY 11, 2023

TABLE OF CONTENTS

Page

I. INTRODUCTION 1
II. RESOURCE TRANSITION MECHANISM (RTM) AND ENVIRONMENTAL COMPLIANCE ADJUSTER (ECA) 5
III. RENEWABLE ENERGY STANDARD TARIFF (REST) 13
IV. DEMAND SIDE MANAGEMENT (DSM) SURCHARGE 13
V. REGULATORY ASSET - EV INFRASTRUCTURE INVESTMENTS & SAN JUAN MATERIALS AND SUPPLY 14
VI. RATE CASE EXPENSES 15
VIII. PROPOSED RATE SCHEDULES AND BILL COMPARISONS 17

ATTACHMENTS

RUCO Recommendated Rates ..... Attachment DBE-1
Bill Comparisons ..... Attachment DBE-2
Company Response to RUCO Data Request 2.06 ..... Attachment DBE-3

EXECUTIVE SUMMARY

RUCO recommends that the Commission reject TEP's proposed Resource Transition Mechanism ("RTM") but retain its Environmental Compliance Adjuster ("ECA"). TEP has requested that the ECA be retained in the event that the Commission rejects the proposed RTM.

RUCO recommends the Commission accept TEP's proposal to eliminate the Renewable Energy Standard Tariff ("REST") and its surcharge and to collect REST-related costs through base rates.

RUCO recommends the Commission accept TEP's proposal to eliminate the Demand Side Management ("DSM") adjuster. Additionally, TEP has requested the Commission facilitate recovery of TEP's DSM costs by authorizing a DSM regulatory asset upon which the Company would earn a return equal to its weighted average cost of capital ("WACC") on the regulatory asset. RUCO recommends against these items being added to the rate base as a regulatory asset. Rather, RUCO recommends that these DSM costs be reflected in a balancing account with no "return on" allowed on any portion of these DSM costs. These DSM costs should be amortized and recovered over time and treated as expense-type items.

TEP proposes the Commission authorize regulatory assets to facilitate recovery of costs associated with EV Infrastructure and San Juan Materials and Supply, with "return on" any capitalized portion at the Company's WACC. As with DSM, RUCO recommends against these costs being reflected in the rate base as a regulatory asset. Rather, RUCO recommends that these costs be reflected in a balancing account with no "return on" any portion of these costs. These costs should be amortized and recovered over time and treated as expense-type items.

To properly recognize cost-causation principles, RUCO recommends the Commission allocate less rate case expense to residential customers and allocate more to non-residential customers. This cost reallocation lowers residential rates, assuming other factors are held constant.

RUCO recommends that the Commission accept TEP's proposal to increase the residential customer charges by $2.00 per month.

Finally, RUCO recommends the Commission approve the rates shown in Attachment DBE-1, which conform to RUCO's recommended revenue requirement for TEP and reflect RUCO's recommended reallocation of rate case expenses.

I. INTRODUCTION

Q. Please state your name, place of employment, position, and business address.

A. My name is Bentley Erdwurm. I am a Public Utility Analyst V for the Residential Utility Consumer Office ("RUCO"). My business address is 1110 W. Washington St., Suite 220, Phoenix, Arizona 85007.

Q. Please describe your professional experience and educational background.

A. I joined RUCO in January 2021. I have over forty years of utility industry experience focused on cost allocation, rate design, revenue and load forecasting, and financial and statistical analysis. I have testified as an expert witness for regulatory agencies (Texas Public Utility Commission, Arizona Corporation Commission, and Idaho Public Utilities Commission) and for utilities in Alabama, Arizona and California. I also teach statistics as an adjunct instructor for the Department of Information Technology and Supply Chain Management at Boise State University. I earned my B.A. in Economics from the University of Dallas and my M.S. in Economics from Texas A&M University.

Q. Please summarize TEP's key rate design proposals and RUCO's recommendations to the Commision for these proposals.

A. ***Resource Transition Mechanism ("RTM") & Environmental Compliance Adjuster ("ECA"):*** First, my testimony addresses TEP's proposal to implement its RTM, which is a "mega" adjuster mechanism that would recover from ratepayers the substantial costs of TEP's planned investments to transition to a more sustainable, cleaner resource mix. The RTM is a significant departure from traditional ratemaking. TEP plans to spend hundreds of millions of dollars to move toward a greener energy future, expenditures that dwarf what TEP heretofore has spent on programs like DSM and REST that have been recovered through adjuster mechanisms. What is important to keep in mind is that historically adjuster mechanisms are the exception to fair value in Arizona, not the rule. As explained in more detail below, adjuster mechanisms should only be used in extenuating circumstances such as where the Company is dealing with costs that are very volatile or outside the utility's control and might cause significant financial harm to the utility if there was not such a mechanism in place. RUCO urges the Commission to reject the RTM as an unwarranted deviation from traditional ratemaking that would apply to a significant portion of TEP's capital budget. Justification of RUCO's position, including a discussion of why RTM harms ratepayers' interests is presented in testimony below.

TEP has requested that if the Commission rejects RTM, then the existing ECA be retained. RUCO recommends the Commission retain the ECA given that it has previously been approved by this Commission. Both the RTM and the ECA are addressed in the direct testimony of Company witness Mr. Dallas Dukes.

Renewable Energy Standard Tariff ("REST"): Second, my testimony addresses TEP's proposal to eliminate the REST and its surcharge and to collect REST-related costs through base rates. (TEP's response to RUCO's DR 2.09). TEP proposes the establishment of a deferral account to track costs above or below test-year levels, with subsequent true-up in future rate cases. This issue is addressed by Mr. Dukes in his direct testimony.

RUCO recommends that the Commission accept TEP's proposal to eliminate the REST and its surcharge and to collect REST-related costs through base rates. TEP's REST proposals conform to previously-expressed Commission positions supporting a reduction in the number of adjusters.

Demand Side Management ("DSM") surcharge: Third, my testimony addresses TEP's proposal to eliminate the DSM surcharge. To conform to previously-expressed Commission positions supporting a reduction in the number of adjusters, RUCO recommends the Commission accept TEP's proposal to eliminate the DSM adjuster.

Additionally, TEP has requested the Commission facilitate recovery of TEP's DSM costs by authorizing a DSM regulatory asset upon which the Company would earn a return equal to its weighted average cost of capital ("WACC") on any capitalized portion of this regulatory asset. RUCO believes that DSM costs should be treated as expenses for ratemaking purposes; therefore, RUCO recommends against allowing a "return on" any portion of DSM costs. RUCO's justification for an expense-type treatment for DSM-related items and the consequences of this treatment are addressed in testimony below. This DSM issue is addressed by Mr. Dukes in his direct testimony.

Electric Vehicle ("EV") Infrastructure Investments and San Juan Materials and Supply: Fourth, my testimony addresses TEP's proposal to establish regulatory assets for Electric Vehicle Infrastructure Investments and San Juan Materials and Supply. As with DSM, TEP proposes that its WACC apply to regulatory assets for Electric Vehicle Infrastructure Investments and San Juan Materials and Supply.

As with DSM, RUCO believes that costs related to EV Infrastructure and San Juan Materials and Supply should be treated as expenses for ratemaking purposes; therefore, RUCO recommends against allowing a "return on" any portion of these items. RUCO's justification for an expense-type treatment for these items and the consequences of this treatment are addressed in testimony below. EV Infrastructure and San Juan Materials and Supply issues are addressed by Mr. Dukes in his direct testimony.

Rate Case Expenses: Fifth, my testimony addresses TEP's allocation of 60% of its proposed $1,270,000 (i.e., $762,000) in rate case expenses to residential customers. RUCO believes the 60% residential allocation is excessive and inconsistent with cost-causation principles. This testimony explains flaws in TEP's proposed rate case expense allocation and RUCO's justification for recommending the Commission reduce the residential rate case expense allocation to 30% of these expenses (i.e. $381,000). The difference in the Company-proposed allocation of rate base expenses to residential customers and the RUCO-recommended allocation is $381,000 ($762,000 - $381,000).

Residential Customer Charge Increase: Sixth, TEP proposes to increase monthly residential customer charges by $2.00. RUCO recommends that the Commission accept TEP's proposal to increase the residential customer charges by $2.00 per month because this results in a more cost-based rate design that better allocates costs to the customers who cause the costs to be incurred. Moreover, the customer charge increase causes residential usage charges to decrease, other things held constant. Further explanation for RUCO's support of the customer charge increase is provided in testimony below.

RUCO Recommended Rates: Finally, RUCO recommends that the Commission accept RUCO's recommended rates, as shown in Attachment DBE-1. RUCO's recommended rate design generally follows the methodology proposed by the Company. RUCO's recommended rates differ from the Company-proposed rates primarily due to differences in the Company-proposed and RUCO-recommended revenue requirements. The only deviation from the Company's methodology is to reallocate $381,000 of rate case expenses from residential customers to non-residential customers.

RUCO supports the Company's overall rate design methodology because it is easy to understand, adequately cost-based and places cost responsibility on cost-causers. RUCO believes that the proposed rate design also offers the Company a reasonable opportunity to recover the costs of providing service.

RUCO presents typical bill impacts in Attachment DBE-2.

II. RESOURCE TRANSITION MECHANISM (RTM) AND ENVIRONMENT COMPLIANCE ADJUSTER (ECA)

Q. Please further elaborate on why RUCO characterizes RTM as a significant departure from traditional ratemaking.

A. TEP's proposed RTM is an adjuster mechanism. Adjuster mechanisms are an exception to the constitutional requirement for the Commission to find fair value when setting rates. This issue was addressed in *Scates v. Arizona Corporation Commission,* 118 Ariz. 531, 535. 578 P.2d 612, 616 (App. 1978). While I am not an attorney, and offer no legal opinions, I have testified as an expert witness in the utility industry for over forty years and I understand the general implications of *Scates*. The *Scates* Court noted that permissible adjuster mechanisms allow rates to adjust for variations in "certain and narrowly defined *operating expenses*." TEP's proposed RTM would recover hundreds of millions of dollars of *capital expenditures*, which is impossible to characterize - as "certain and narrowly defined *operating expenses*." (Emphasis added.) The proposed RTM would recover significant portions of TEP's *capital* budget, not just items treated primarily as expenses for regulatory accounting purposes.

Moreover, the RTM would allow TEP regular and repeated rate increases outside of a rate case, specifically to fund the transition to a greener resource base. This constitutes single issue ratemaking. Single-issue ratemaking occurs when utility rates are adjusted, or costs deferred, in response to a change in a cost item considered in isolation from countervailing factors such as increases in revenues or decreases in other expenses. From the ratepayers' perspective, single-issue ratemaking is biased and undesirable because it precludes opportunities - available through the rate case process - to identify efficiencies, process improvements or any other changes in revenues and/or costs that could help offset the rate impacts associated with the "single issue." To mitigate the adverse consequences of single issue ratemaking on utility customers, adjuster mechanisms should only be used in extenuating circumstances such as where the utility is dealing with costs that are very volatile or outside its control. Fuel and purchased power costs for electric utilities are often recovered through a fuel adjustment mechanism because these items are often viewed **as volatile**, often **unpredictable**, and to a varying extent **beyond the control of the utility**.

RTM applies to the costs of investing in a green portfolio, and these costs are clearly in the Company's control. Moreover, the risk involved is in the Company's control, and this risk justifies a portion (in excess of the risk free rate) of the utility's return on investment in traditional ratemaking. The Company now wants to change this dynamic by shifting the risk to ratepayers while still earning a return on this shifted risk - risk that would be borne by ratepayers if RTM is approved. RTM represents a substantial deviation from traditional ratemaking, differs substantially from the type of adjusters unopposed in past proceedings by RUCO (e.g., fuel adjusters), and should be rejected by this Commission.

Q. Why do utility companies support adjuster mechanisms to recover the costs of capital projects?

A. Adjuster mechanisms designed to recover significant capital investments advance the narrow self-interests of utilities by bypassing the traditional rate case process for plant additions, which means (1) more risk shifting from utilities to their customers, as described above, (2) less regulatory oversight and review, (3) less stakeholder input, and (4) reduced regulatory lag. Regulatory lag is the time between when a utility makes an investment and cost recovery begins.

Under traditional ratemaking, the Commission authorizes the addition of utility plant to the Company's rate base only after making "used and useful" and prudency determinations in a rate case proceeding. A rate case provides opportunities for multiple parties to ask critical questions, prepare analyses and articulate positions, and if necessary, debate the prudency and "used and useful" characterization of pending plant additions. In a rate case, sworn witnesses must face cross examination and defend their positions. The truncated review process for adjusters simply does not provide the same opportunity for rigorous examination.

Typically, an adjuster filing follows a Plan of Administration ("POA") procedure, which usually consists of an application to Staff with a relatively short mandated response time. Parties are extremely challenged to vet the application and independently determine if the true-ups/adjustments are accurate and if counterbalancing offsets have been fully explored. Economic entities - whether utilities, non-regulated businesses, or consumers - generally respond to their operating environments. Because adjuster mechanisms provide less regulatory oversight than the rate case process, among other reasons, they are attractive to utilities. However, as mentioned in the *Scates* case, a "piecemeal approach" to ratemaking is "fraught with potential abuse" and serves "...both as an incentive for utilities to seek rate increases when cost in a particular case rise, and as a disincentive for achieving countervailing economies in the same or other area of their operations." S*cates v. Arizona Corporation Commission,* 118 Ariz. 531, 534. 578 P.2d 612, 615 (App. 1978).

RUCO is not suggesting that any of TEP's adjusters are being abused, but warns that they could be abused. RUCO strongly recommends that the Commission exercise caution by assuming there is a reasonable risk that reduced regulatory oversight could harm the interests of ratepayers.

The traditional rate case process is fair to both the utility and its customers. It allows the utility to recover its costs - both return *of* (depreciation) and return *on* investment. The Commission's oversight efforts - its "used and useful" and prudency determinations - protect the ratepayers' interests.

Q. TEP has noted that the Commission reviewed future resource plans in the Company's Integrated Resource Plan ("IRP") filings. Can this review substitute for "used and useful" and prudency determinations in a rate case proceeding?

A. No. The Commission only acknowledges IRP filings. There is no "acceptance" or "approval." This important distinction has been made clear by both Staff in its IRP comments and by the Commission.

Q. Will Commission rejection of the RTM place TEP in financial distress?

A. No. TEP did not claim that rejection would result in financial distress.

Q. Will rejection of the RTM impede TEP's progress in moving toward a greener, less carbon intensive resource base?

A. It should not. TEP has been granted an exclusive right to serve its certificated area, and with that privilege comes an obligation to move toward an optimal resource base. It should be unnecessary to have to provide extraordinary rate treatment to incent TEP to act in its customers' interests. Traditional rate cases provide ample opportunities for TEP to earn a fair return of and return on invested capital.

The rejection of the RTM would also facilitate more thoughtful and purposeful Commission oversight regarding the speed and direction of the transition from fossil fuel generation to greener alternatives. RUCO believes these policy decisions should be revisited periodically through the rate case process. Circumstances change and the extra time afforded in rate cases allows for more informed decision making. For example, disruptive technologies such as hydrogen may affect the economic viability of current EV applications, thus impacting cost recovery for EV infrastructure. Unforeseen changes in the relative costs of small scale nuclear, wind, solar and transmission assets may drive a much different capital expansion plan. RUCO is also concerned about the possibility of stranded costs resulting from disruptive technologies. Finally, as discussed extensively above, rate case review is the proper approach to meet the constitutional requirement for the Commission to find fair value when setting rates. Costs can be effectively recovered through traditional ratemaking and there is no need for extraordinary ratemaking - specifically the RTM - at this time.

Q. Should adjusters apply to Company-owned capital projects?

A. No. As discussed above, *Scates* favored limiting adjuster mechanisms to expense-type items, not capital items, which, unlike operating expenses, must be determined in a rate case to be used and useful and prudent prior to inclusion in rate base and cost recovery. Adjusters should function as passthrough mechanisms that facilitate more immediate cost recovery of narrowly defined operating expenses. Expense treatment dictates that adjusters should ***exclude*** a "return on" component.

Q. You stated above that the adjusters reduce regulatory lag, which is the time between when a utility makes an investment and cost recovery begins. Is this also true for TEP's proposed RTM

A. Yes. TEP's proposed RTM will result in bill increases sooner than under traditional ratemaking.

Q. Why do you believe that RTM will result in bill increases sooner?

A. TEP's President and Chief Executive Officer, Ms. Susan Gray, describes a situation where customers see rate increases sooner in her direct testimony. She states: "The proposed Resource Transition Mechanism ("RTM") would facilitate development of cleaner, less carbon intensive resources at costs that would be passed along gradually to customers, avoiding rate shocks that could result from allowing such costs to accumulate between rate cases." (Direct testimony of Susan Gray, page 5, lines 13-17). Avoiding the "accumulation between rate cases" means accelerating the cost recovery process as well as the amount of cost as already explained.

Additionally, TEP's response to RUCO's Data Request 2.06 describes a simplified scenario where a revenue requirement collected from customers with RTM is compared to a revenue requirement without RTM over a four year period, with Year 4 corresponding to the filing of a rate case. In all four years the revenue requirement <u>without</u> RTM is less than or equal to the revenue requirement <u>with</u> RTM, which means that in this example ratepayers NEVER pay more for service without RTM. Yet in two of the four years (Years 2 and 3), the RTM revenue requirement exceeds the revenue requirement without RTM. Keep in mind that this is TEP's example, not RUCO's. A copy of TEP's response to RUCO's DR 2.06 is included with this testimony as Attachment DBE-3.

Based on Ms. Gray's testimony and TEP's response to DR 2.06, it is clear that TEP believes that its proposed RTM will result in bill increases sooner than under traditional ratemaking.

Q. Ms. Gray states that "Customers clearly benefit from the more gradual bill increases that would result" from RTM. (Susan Gray Direct Testimony, page 5). Please comment on her statement.

A. The "more gradual bill increases" description cited by Ms. Gray DOES NOT support Commission approval of RTM. The reason is simple: Based on TEP's own testimony and data request responses, cited above, TEP does not provide a single example where RTM results in lower bills over the four year period after RTM implementation. TEP has only provided examples where rates are higher with RTM. While there may be some appeal to ratepayers for some *general* notion of "gradualism", characterized by multiple small rate increases rather than one larger one, the appeal evaporates in this specific case of RTM because bills under RTM over the next four years are ALWAYS greater than or equal to bills without RTM. Moreover, as explained above, legitimate offsets to costs normally contemplated in traditional ratemaking are not considered as part of the single issue ratemaking process. The result is higher overall rates - which counters the benefits of gradualism.

In past cases where the Commission cites "gradualism" as a ratemaking objective, the term is used much differently than when TEP has used it (or similarly, phrases like "more gradual bill increases") in this case. In my experience, the Commission cites "gradualism" as a rate design objective only when rates are lower than they would be without the application of "gradualism." I cannot recall a single instance where a Commission decision celebrates a higher rate and cites "gradualism."

An example of the type of "gradualism" cited in Commission decisions is found in the Commission's Decision No. 78644 (dated July 27, 2022) for Global Water, approving the three-year phase in of rates for Global's Eagletail, Tonopah and Turner Ranches service areas. For the first two years these rates are in effect, they are designed to collect less than the authorized revenue requirement, with full recovery delayed until the third year. Gradualism is an ambiguous term and does not always benefit the ratepayer.

Q. Are you surprised that RTM never decreased bills over the four-year period cited in TEP's response to RUCO's DR 2.06?

A. No. As described above, an adjuster designed to recover the significant capital cost of moving to a greener resource mix constitutes the type of single issue ratemaking that *Scates* cautioned against. The proposed RTM accelerates cost recovery associated with moving to the greener resource mix (the single issue), which tends to increase bills. Yet RTM precludes opportunities for consideration of the type of counterbalancing offsets that rate cases offer.

Additionally, RUCO is concerned that adjusters historically have been subject to over/under-collection, and there is no reason to believe that these issues would not also arise with the RTM. The true-ups associated with over/under-collections can create rate volatility and undermine the type of rate stability and "gradualism" that the Commission seeks.

Q. You mentioned above that the Commission has indicated its desire to see TEP reduce the number of adjusters. Please comment on whether TEP's proposed RTM addresses the Commission's concerns.

A. With respect to reducing the number of adjusters, RUCO believes RTM is a step in the wrong direction. Any claim to addressing the Commission's concerns rings hollow if TEP's remedy is to replace several current adjusters (e.g., REST, DSM, and ECA) with the RTM "mega" adjuster. While technically, it is true that the number of adjusters is reduced, approval of the RTM would make TEP's ratemaking process even more adjuster-driven and more susceptible to the pitfalls of single issue ratemaking, as described in *Scates*. As mentioned above, costs recovered through RTM would dwarf what TEP heretofore has spent on programs like DSM and REST.

III. RENEWABLE ENERGY STANDARD TARIFF ("REST")

Q. Why is RUCO recommending Commission approval of TEP's proposal to eliminate the REST and its surcharge and to collect REST-related costs through base rates?

A. The Commission has expressed its desire in past proceedings to see TEP reduce the number of adjusters. TEP is not requesting the establishment of a regulatory asset for REST-related costs. TEP will track costs above or below test-year levels, with subsequent true-up in rate case proceedings. RUCO believes that TEP's proposal conforms to past positions expressed by the Commission to reduce the number of adjusters.

IV. DEMAND SIDE MANAGEMENT ("DSM") SURCHARGE

Q. Above, you indicated that RUCO recommends the Commission accept TEP's proposal to eliminate the DSM adjuster, conditioned on DSM costs being treated like expense items for ratemaking purposes. Please explain RUCO's justification for its recommendation.

A. Elimination of the DSM adjuster conforms to past positions expressed by the Commission to reduce the number of adjusters. As with REST, RUCO agrees with TEP's proposal to eliminate the adjuster. However, RUCO recommends that the Commission reject TEP's proposal for a DSM regulatory asset upon which the Company would earn a return equal to its WACC on any capitalized portion of the regulatory asset. RUCO recommends balancing accounts for these costs, recovered as expense items and amortized over time. Because the items are treated as expenses under RUCO's recommendation, there is a dollar for dollar "return of" the entire cost but not a "return on" the cost.

DSM expenditures fund successive three-year DSM programs. Given the relatively short duration of these programs, expense treatment is appropriate. Also, Company representatives have indicated in informal discussions that most of the DSM items being considered are expense-type items. Treating DSM costs as expenses will exclude a "return on" investment component and will therefore result in lower bills for ratepayers.

V. REGULATORY ASSET - EV INFRASTRUCTURE INVESTMENTS & SAN JUAN MATERIALS AND SUPPLY

Q. Has TEP proposed regulatory assets for EV Infrastructure Investments and San Juan Materials and Supply - similar to their DSM regulatory asset proposal?

A. Yes. As with DSM, TEP is proposing that these regulatory assets earn a return equal to its WACC on any capitalized portion of the regulatory asset. As with DSM, RUCO recommends balancing accounts for these costs, recovered as expense items and amortized over time. Because the items are treated as expenses under RUCO's recommendation, there is a "return of" the entire cost of the EV Infrastructure Investments and San Juan Materials and Supplies, but no "return on" component.

VI. RATE CASE EXPENSES

Q. Please explain why the allocation of rate case expense to residential customers should be reduced from approximately 60% of the $1,270,000 expense ($762,000), as proposed by TEP, to 30% of the expense ($381,000), as recommended by RUCO, which is a difference of $381,000.

A. TEP allocates rate case expense in its class cost of service study ("CCOSS") using its composite allocator "OMXFXAG". This allocator is used to allocate certain administrative-type expenses that could serve multiple functions. I have seen this type of composite allocator used many times in past rate case proceedings - for different utilities - to allocate administrative-type expenses. However, in this instance it is not appropriate for allocating rate case expenses because it does not capture what drives TEP's rate case expenses. Specifically, the OMXFXAG allocation approach fails to recognize that heightened intervention activity in TEP rate cases by numerous stakeholders (by Arizona standards) is driving relatively high rate case expenses (again, by Arizona standards) compared to other large investor owned utilities in the state. This intervention activity is not performed at the behest of TEP's residential customers, it does not serve their interests, and residential customers should not be paying for it. It is not a reasonable expense. RUCO recommends that the Commission adjust the residential allocation downward from TEP's proposed 60% to 30%, a portion that will bring TEP's rate case expense per customer more in line with rate case expenses for other large investor-owned utilities in Arizona. For comparison, RUCO notes that on a *dollars per customer* basis, TEP's proposed rate case expense (around $2.90 per customer) is significantly higher than the comparable value for rate case expense approved in the case filed by Southwest Gas on May 1, 2019 (Docket No. G-01551A-19-0055); less than $0.55 per customer, after adjusting for inflation.

Q. Has RUCO accounted for its recommended reallocation of rate case expenses in its rate recommendations?

A. Yes. The rates shown in Attachment DBE-1 reflect RUCO's recommended shift of $381,000 of TEP's proposed rate case expenses from residential customers to non-residential customers. The $381,000 is the difference between TEP's proposed residential rate case expense allocation ($762,000) and RUCO's recommended residential rate case expense allocation ($381,000).

VII. $2.00 INCREASE IN MONTHLY RESIDENTIAL CUSTOMER CHARGES

Q. Why does RUCO recommend that the Commission approve TEP's proposed $2.00 increase in the customer charge?

A. The customer charge increase is cost-based. Increasing the customer charge also results in a lower usage charge, other things constant. A residential customer charge for electric service should cover the incremental cost of providing that service. At a minimum, the customer charge should cover costs related to metering, meter reading, billing, customer service and the service drop. I have referred in the past to limiting customer charges to these items as a "bare-bones" approach to customer charge determination. It's a bare bones approach because it covers only the incremental cost of making service available to a customer. TEP's proposed charge, including the $2.00 monthly increase, is less than this incremental cost. If the customer charge is too low (significantly lower than incremental cost), customers who use little or no electricity are subsidized by other customers on the system. A failure to follow cost-based ratemaking would allow customers who already have the lowest bills to be subsidized by others who use more electricity and have higher bills. In RUCO's view that is an undesirable outcome. Also, from a policy perspective, setting customer charges too low will adversely affect users with higher than average usage - possibly resulting from being a household with more members (larger families) or from living in older, substandard housing with inadequate insulation, leaky ductwork, or inefficient HVAC equipment.

VIII. PROPOSED RATE SCHEDULES AND BILL COMPARISONS

Q. Has RUCO prepared a schedule of proposed rates?

A. Yes. Please see Attachment RD-DBE-1. The rate structure follows the Company proposal with rates scaled to conform to RUCO's proposed revenue requirement.

Q. Has RUCO prepared bill comparisons between current rates, Company-proposed rates, and RUCO recommendations?

A. Yes. Please see Attachment RD-DBE-2.

Q. Does this conclude your direct testimony

A. Yes, it does.

ATTACHMENT DBE-1

RUCO Recommended Rates

ATTACHMENT DBE-2

Bill Comparisons

ATTACHMENT DBE-3

Company Responses to RUCO Data Request 2.06

TUCSON ELECTRIC POWER COMPANY

DOCKET NO. E-01933A-22-0107

DIRECT TESTIMONY
OF
JOHN A. CASSIDY, CRRA

ON BEHALF OF THE
RESIDENTIAL UTILITY CONSUMER OFFICE

JANUARY 11, 2023

TABLE OF CONTENTS

Page

I. INTRODUCTION 1
II. SUMMARY OF TESTIMONY AND RECOMMENDATIONS 2
III. ECONOMIC PRINCIPLES APPLICABLE TO ARIZONA 4
IV. GENERAL ECONOMIC CONDITIONS 6
V. CAPITAL STRUCTURE AND COST OF DEBT 21
VI. SELECTION OF PROXY GROUP 22
VII. DCF ANALYSIS 22
VIII. CAPM ANALYSIS 26
IX. RUCO RESPONSE TO COMPANY'S COST OF CAPITAL WITNESS MS. ANN E. BULKLEY 32
XI. FAIR VALUE RATE OF RETURN 35
XII. CONCLUSION AND RECOMMENDATIONS 36

ATTACHMENTS

John A. Cassidy – Regulatory Experience .... Attachment 1
Value Line Updates – RUCO Proxy Group .... Attachment 2

EXHIBITS

Changes to FOMC Targeted Federal Funds Rate, 2006-2022 .... JAC-A
10-Year Breakeven Inflation, Measured over 1-month and 3-month Periods, January-December, Years 2021 and 2022 .... JAC-B

SCHEDULES

Weighted Average Cost of Capital JAC-1
Cost of Common Equity JAC-2
Discounted Cash Flow Model JAC-3
Capital Asset Pricing Model JAC-4
Economic Indicators JAC-5

EXECUTIVE SUMMARY

RUCO recommends that the Commission adopt a 6.74 percent overall rate of return for Tucson Electric Power Company ("TEP," or "Company"), based upon (i) a capital structure comprised of 45.68 percent Long-Term Debt and 54.32 percent Common Equity; (ii) a 3.82 percent cost of Long-Term Debt; and (iii) RUCO's recommended 9.20 percent cost of common equity, as shown below:

	Weight	Cost	Weighted Cost
Long-Term Debt	45.68 %	3.82 %	1.75 %
Common Equity	54.32 %	9.20 %	5.00 %
Overall Rate of Return			6.74 %

RUCO obtained Common Equity cost estimates for a proxy group of fifteen (15) sample companies from two cost of equity estimation models: the Constant Growth Discounted Cash Flow Model ("DCF"), and the Capital Asset Pricing Model ("CAPM"). The range of estimates obtained from each of the two models employed by RUCO are as follows:

Cost of Equity Estimation Model	Range
Constant Growth Discounted Cash Flow ("DCF")	9.19% - 9.24% (9.21% mid-point)
Capital Asset Pricing Model ("CAPM")	8.88% - 9.51% (9.20% mid-point)

As shown, RUCO obtained estimates from the Constant Growth DCF model ranging from 9.19 percent to 9.24 percent, with a midpoint of 9.21 percent. RUCO obtained CAPM estimates ranging from 8.88 percent to 9.51 percent, with a midpoint of 9.20 percent.

TEP's proposed capital structure is less highly leveraged than the Proxy Group employed by Company witness, Ms. Bulkley, and thus has less exposure to financial risk. In order to give recognition to differences in financial risk exposure, RUCO obtained two CAPM estimates; (i) an 8.88 percent Hamada CAPM estimate at the Company-Proposed Debt Ratio (i.e., 45.68%), and (ii) a 9.51 percent CAPM estimate at the Proxy Group Debt Ratio (i.e., 52.89%). RUCO concludes that TEP's required cost of common equity lies within a range of 8.88 percent to 9.51 percent (9.20 percent mid-point), based upon the Hamada CAPM at the Company-Proposed Debt Ratio (i.e., 45.68%), and the CAPM at Proxy Group Debt Ratio (i.e., 52.89%). As shown below, RUCO's recommended 9.20 percent cost of equity represents the arithmetic mean of the three estimates obtained by RUCO's DCF and CAPM analyses.

Cost of Equity Estimation Model	Common Equity Cost Rate
Constant Growth DCF	9.21 %
CAPM -- at Proxy Debt Ratio	9.51 %
CAPM – at Company-Proposed Debt Ratio	8.88 %
RUCO Recommended Cost of Common Equity	9.20 %

RUCO also calculates a Fair Value Rate of Return ("FVROR") for the Company. RUCO recommends a return on the fair value increment ("FVI") of 0.00 percent. RUCO recommends a

FVROR of 4.66 percent, based on a 0.00 percent FVI cost rate for Tucson Electric Power Company.

RUCO will also demonstrate that the 10.25 percent common equity cost rate put forth by Tucson Electric Power Company witness, Ms. Ann W. Bulkley, significantly overstates the Company's actual cost of equity.

I. INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is John A. Cassidy. I am a Public Utilities Analyst V with the Residential Utility Consumers Office ("RUCO"). My business address is 1110 W. Washington Street, Suite 220, Phoenix, AZ.

Q. Please describe your educational background and professional experience.

A. I hold a Bachelor of Arts degree in History from Arizona State University, a Master of Library Science degree from the University of Arizona, and a Master of Business Administration degree with an emphasis in Finance from Arizona State University. I have been awarded the professional designation Certified Rate of Return Analyst ("CRRA") by the Society of Utility and Regulatory Financial Analysts ("SURFA") based upon experience and the successful completion of a written examination. I have fifteen years of professional regulatory work experience as a Public Utilities Analyst, both with RUCO and the Arizona Corporation Commission ("ACC") Staff, and have testified in numerous rate proceedings as a cost of capital witness before this Commission. Additionally, I have attended utility related seminars sponsored by SURFA, the National Association of State Utility Consumer Advocates ("NASUCA"), and the National Association of Regulatory Utility Commissioners ("NARUC"). Attachment 1 contains a summary of my prior regulatory work experience.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to present RUCO's recommendations for the establishment of a fair value rate of return. For purposes of establishing a fair value rate of return on its invested capital in this proceeding, the Company has elected to use the average of its original cost rate base ("OCRB") and its reconstruction cost new depreciation ("RCND") as its fair value rate base ("FVRB").

Q. Will RUCO provide direct testimony on the rate base, operating income and rate design issues in this proceeding?

A. Yes. The Direct Testimony of RUCO witness Ms. Crystal Brown will address issues relating to rate base, the Direct Testimony of Mr. Jeffrey Michlik will address the issue of operating income, and the Direct Testimony of Mr. Daniel Erdwurm will address rate design, rate case expense, and adjustor mechanisms.

II. SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Briefly summarize how your cost of capital testimony is organized.

A. My cost of capital testimony is organized into ten (10) different sections as identified in my "Table of Contents." In summary, I have derived cost of equity estimates obtained from both the Constant Growth Discounted Cash Flow ("DCF") model and the Capital Asset Pricing Model ("CAPM"). The DCF and CAPM are market-based cost of equity estimation models, and both have consistently been employed by RUCO and ACC Staff in prior rate proceedings. Additionally, the DCF and CAPM are methodologies which the ACC has traditionally given the most weight when establishing authorized rates of return for utilities operating within its Arizona jurisdiction. As will be discussed, RUCO's recommended cost of equity in this proceeding represents the arithmetic mean (i.e., simple average) of the cost of equity results obtained from the DCF and CAPM models, with recognition given to CAPM estimates obtained at (i) the Proxy Group Debt Ratio, and (ii) a Hamada CAPM at the Company-Proposed Debt Ratio. RUCO incorporates two CAPM estimates into its analysis in recognition of TEP having less exposure to financial risk than the sample companies comprising the Proxy Group employed by Company witness, Ms. Anne E. Bulkley.

Company witness Bulkley obtains cost of equity estimates from (i) the Constant Growth DCF model, (ii) the CAPM, (iii) the Empirical Capital Asset Pricing Model ("ECAPM"), and (iv) a Bond Yield Plus Risk Premium methodology ("RP" model). My testimony will conclude with a brief discussion of Ms. Bulkley's cost of equity analyses and recommendations, and how they serve to overstate the Company's actual cost of equity.

Q. Please summarize the cost of capital recommendations to be addressed in your testimony.

A. Based upon the results of my cost of capital analysis, RUCO makes the following recommendations: RUCO recommends that the Commission adopt a 6.74 percent overall rate of return for the Company, based upon (i) a capital structure comprised of 45.68 percent long-term debt and 54.32 percent common equity, (ii) a 3.82 percent cost of long-term debt, and (iii) a cost of common equity of 9.20 percent. RUCO's cost of capital recommendations are as follows:[1]

	Weight	Cost	Weighted Cost
Long-Term Debt	45.68 %	3.82 %	1.75 %
Common Equity	54.32 %	9.20 %	5.00 %
Overall Rate of Return			6.74 %

RUCO's recommended 9.20 percent cost of common equity is computed as the arithmetic mean of estimates derived from the Constant Growth DCF and CAPM models. Details of the computation of RUCO's recommended cost of common equity are summarized below:[2]

[1] *See* Schedule JAC -1 (Page 1).
[2] *See* Schedule JAC-2.

Cost of Equity Estimation Model	Common Equity Cost Rate
Constant Growth DCF	9.21 %
CAPM -- at Proxy Debt Ratio	9.51 %
CAPM – at Company-Proposed Debt Ratio	8.88 %
RUCO Recommended Cost of Common Equity	9.20 %

III. ECONOMIC PRINCIPLES APPLICABLE TO ARIZONA

Q. What are the basic economic principles which apply in the determination of a fair rate of return for regulated public utilities in Arizona?

A. For regulated public utilities in Arizona, rates are established in a manner designed to allow for recovery of the utility's costs, including capital costs. This is traditionally referred to as "cost of service" ratemaking. Rates are established using the "rate base – rate of return" concept, wherein utilities are allowed to recover specific operating expenses, taxes and depreciation, and granted an opportunity to earn a fair value rate of return on the assets utilized (i.e., fair value rate base) in providing service to ratepayers. Rate base is derived from the asset side of the utility's balance sheet, while rate of return is developed from the liability/stockholders' equity side of the balance sheet. The revenue impact of the cost of capital in rates is determined by multiplying rate base by rate of return. In the instant docket, RUCO is recommending an overall OCRB rate of return of 6.74 percent for TEP.

Q. Is the Company proposing that its original cost rate base also be used as its fair value rate base ("FVRB")?

A. No. The Company proposes that the average of its OCRB and RCND rate bases be used as its FVRB. As will be discussed, RUCO recommends a 4.66% return on the Company's FVRB, based upon RUCO's recommended 0.00 percent Fair Value Increment ("FVI") cost rate.

Q. What is the meaning of a "fair rate of return" when analyzing a rate case application?

A. From an economic standpoint, a "fair rate of return" is one which allows an efficient and economically well managed utility the ability to maintain its financial integrity, attract capital, and establish comparable returns for similar risk investments. These concepts are derived from economic and financial theory and are generally implemented using financial models and economic concepts. From a technical perspective, a "fair rate of return" is an ex post (after the fact) earned return on an asset base. Conversely, the cost of capital is an ex ante (before the fact) expected, or required, return on a capital base. In regulatory proceedings, the two terms are often used interchangeably.

Q. As regulated entities granted natural monopoly status, are public utilities guaranteed to earn their authorized rate of return?

A. No, they are not. Public utilities are afforded an opportunity to earn their authorized rate of return; they are not guaranteed to earn the rate of return authorized in a rate case. Many factors are involved in determining a rate of return. However, investments in new plant assets made subsequent to a rate case and/or increases to operating expenses between rate cases can have a negative impact on a utility's realized rate of return. Conversely, an increase in revenues and/or a decrease in operating expenses can have a positive impact on the earned rate of return. In the former scenario, a public utility will generally file for a rate increase. In the latter scenario, should a public utility earn a rate of return in excess of that approved by a utility commission, then the commission may instruct the utility to file a rate application in order that new rates be established to provide rate relief to ratepayers.

IV. GENERAL ECONOMIC CONDITIONS

Q. Why are economic and financial conditions important in the determination of the cost of capital for a regulated public utility such as TEP?

A. Economic and financial conditions are important because the cost of capital, both fixed-cost debt as well as common equity, is largely determined by current and future economic and financial conditions. At any given time, the cost of capital is influenced by each of the following: (i) the level of economic activity (i.e., economic growth); (ii) the stage of the business cycle; (iii) the rate of inflation; and (iv) expected future economic conditions. That current and future economic and financial conditions largely determine the cost of equity is consistent with the Court's ruling in the *Bluefield* decision, which held that:

> "[a] rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally." Bluefield, 262 U.S. at 679.[3]

Measures of general economic indicators influencing the cost of capital are presented in Schedule JAC-5 (Pages 1-6).

Q. Briefly describe the recent trends in economic conditions and their impact on capital costs over the past thirty years?

A. From the early 1980's through the end of 2007, the United States economy experienced a period of relative stability. This period was characterized by longer economic expansions, small contractions, low and/or declining inflation, and declining interest rates and other capital costs. In 2008 and 2009, however, the economy experienced a steep decline as a result of the sub-prime mortgage lending crisis, and this had a negative impact on financial

[3] *Bluefield Water Works and Improvement Company v. Public Service Commission of the State of West Virginia* (262 U.S. 679), as cited in Parcell, David C., *The Cost of Capital: A Practitioner's Guide*, prepared for the Society of Utility and Regulatory Financial Analysts (SURFA): 2010 Edition (p.26).

markets, both domestically and internationally. This economic decline is generally considered to be the worst financial crisis since the Great Depression, and is often referred to as the 'Great Recession.' As a consequence, in 2008 the United States Federal Reserve Bank ("Fed") and central banks in other foreign countries initiated accommodative monetary policies to stimulate economic growth and reduce unemployment in an effort to recover from this worldwide recession.

The recession bottomed out in June 2009, with the economic recovery continuing through 2019. However, with the onset of the COVID-19 pandemic in early 2020, global economies once again experienced a sharp decline, with the national unemployment rate rising from 3.8 percent in Q1 2020 to a level of 13.1 percent in Q2 2020. Thanks to the development of a COVID-19 vaccine, in combination with the Fed once again instituting an accommodative monetary policy, lowering the Federal Funds rate[4] to its 0.00% - 0.25% Effective Lower Bound ("ELB"), the economic downturn was relatively short lived, and confidence restored to the markets by late 2020. At present (Q3 2022), the national unemployment rate stands at 3.6 percent, while unemployment at the State level currently stands at 3.5 percent.[5]

Throughout the period 2010-2020, inflation, as measured by the Consumer Price Index ("CPI") had been kept at bay, the average annual rate (i.e., 1.73 percent) remaining well below the Fed's targeted 2.0 percent annual rate. Beginning in 2021, however, the annual rate of inflation rose to 7.0 percent, a level not seen in almost forty years. As a consequence, Federal Reserve Chairman, Jerome Powell, stated that it is "absolutely essential to restore price stability," and announced that the Fed plans to "expeditiously" hike short-term interest

[4] The Federal Funds Rate is the short-term interest rate the Fed charges banks for overnight deposits.
[5] Council of Economic Advisors, United States Department of Labor, Bureau of Labor Statistics, *Economic Indicators*, various issues. https://www.govinfo.gov/app/collection/econi/2022

rates in an effort to slow economic growth and lower the rate of inflation, and do so in a manner which would prevent the economy from going into recession.[6]

Q. Has inflation continued to rise in 2022?

A. Yes. The following shows that CPI inflation, measured both on a month-over-month ("M-M") and year-over-year ("Y-Y") basis, has continued to rise in 2022.[7]

Changes to CPI Inflation in 2022

	Month-over-month	Year-over-year
January	0.6 %	7.5 %
February	0.8 %	7.9 %
March	1.2 %	8.5 %
April	0.3 %	8.3 %
May	1.0 %	8.6 %
June	1.3 %	9.1 %
July	0.0 %	8.5 %
August	0.1 %	8.3 %
September	0.4 %	8.2 %
October	0.4 %	7.7 %
November	0.1 %	7.1 %

As shown, CPI inflation measured on a M-M (i.e., 1.3%) and Y-Y (i.e., 9.1%) basis rose to their highest levels in June 2022. The 9.1 percent annualized rate in June was the highest in more than four decades (i.e., November 1981), and driven by a "big jump in gasoline prices," with "shelter and food prices being major contributors."[8] CPI inflation has since moderated, with the annualized 7.1 percent rise in consumer prices in November 2022 being

[6] Cox, Jeff, "Powell Says Taming Inflation 'Absolutely Essential,' and a 50 Basis Point Hike possible for May," *cnbc.com*, updated April 22, 2022. https://www.cnbc.com/2022/04/21/powell-says-taming-inflation-absolutely-essential-and-50-basis-point-hike-on-the-table-for-may.html

[7] Council of Economic Advisors, Economic Indicators, November 2022 (p. 24). https://www.govinfo.gov/app/collection/econi/2022/11

[8] Rubin, Gabriel T., "U.S. Inflation Hits New Four-Decade High of 9.1%," *wsj.com* (July 13, 2022). https://www.wsj.com/articles/us-inflation-june-2022-consumer-price-index-11657664129

the "slowest 12-month pace since December 2021." Measured M-M (i.e., 0.1%), consumer prices in November 2022 "softened significantly," with prices for "gasoline, utility, medical care services and used-car prices all falling."[9]

Q. Did Fed officials anticipate this rapid rise in inflation?

A. No. Inflation first began to surge in June 2021, and at that time Fed Chair Powell and former Fed Chair, Janet Yellen,[10] stated they believed higher inflation to be 'transitory,' "*in part because unemployment was still 5.9%, and had fallen as low as 3.5% in 2019 without inflation going up*."[11] (emphasis added) Subsequently, however, both Fed Chair Powell and Secretary Yellen publicly conceded that they made mistakes in the handling of inflation, and now acknowledge that "inflation is unlikely to recede quickly."[12] In an interview, Fed Chair Powell further stated: "If you look back in hindsight then, yes, it probably would've been better to have raised rates earlier."[13]

Q. In regards to inflation, would it be fair to say that Fed Chair Powell and Secretary Yellen "misread" the economy?

A. Yes. As noted by the authors of a recent Wall Street Journal article,[14] Fed officials "misread the economy," and redeployed the same low-interest-rate monetary policy "playbook" employed in the 2007-2009 financial crisis to the COVID-19 pandemic crisis:

> "But the pandemic economy turned out to be fundamentally different. While the [2007-09] financial crisis primarily *dented demand* by businesses and

[9] Guilford, Gwynn, "U.S. Inflation Eased in November, CPI Report Shows," *wsj.com* (December 13, 2022). https://www.wsj.com/articles/us-inflation-november-2022-consumer-price-index-11670883405?mod=economy_more_pos11
[10] Ms. Yellen now serves as Secretary of the Treasury in the Biden administration.
[11] Timiraos, Nick and Jon Hilsenrath, "How the Fed and the Biden Administration got Inflation Wrong," *wsj.com*, June 13, 2022. https://www.wsj.com/articles/inflation-economy-federal-reserve-11655134682?mod=article_inline
[12] Ibid
[13] Ibid
[14] Ibid

> consumers, the pandemic *undercut supply*, resulting in persistent shortages of raw materials, container ships, workers, computer chips and more.
>
> Unemployment fell and inflation rebounded more quickly than policy makers expected—yet they stuck with the old playbook. That exacerbated the supply-and-demand mismatches and helped drive inflation up, reaching 8.6% in May, its highest in 40 years." (emphasis added)

Q. Were Fed officials the only professional economists to have "misread" the economy in the manner noted above?

A. No, they were not, as evidenced by the following:

> "Many professional economists, using models similar to those used by Mr. Powell and Ms. Yellen, agreed with them that the inflation surge would be transitory. In July 2021, private forecasters surveyed by The Wall Street Journal projected inflation would recede to 2.4% by the end of 2022. They now project 4.8% [inflation] at year-end."[15]

Furthermore, 'bad luck' has made a bad situation worse, and other countries are experiencing high inflation, which suggests that central bankers in those countries made similar policy errors:

> "Private forecasters and nonpartisan congressional scorekeepers similarly failed to anticipate the magnitude and duration of higher inflation. There was also *bad luck*. New Covid variants, Russia's invasion of Ukraine and China's Covid-related lockdowns have made a bad situation worse. And high inflation isn't solely the result of U.S. policy errors: It will end the year at 7.2% in Germany, 8.8% in Britain, 6.1% in Canada, and 6.8% in the U.S., J.P. Morgan projects."[16] (emphasis added)

---

[15] Ibid
[16] Ibid

Q. In addition to hiking short-term interest rates, are there other measures the Fed can take to remove economic stimulus and lift borrowing costs to fight inflation?

A. Yes. The Fed has announced that in addition to hiking short-term interest rates it plans to shrink its $9 trillion asset portfolio of Treasury securities and mortgage bonds. Specifically,

> "Fed officials will allow up to $30 billion in Treasurys and $17.5 billion in mortgage bonds to roll off every month in June, July and August. After that, they will allow $60 billion in Treasurys and $35 billion in mortgage securities to run off every month. Reducing the portfolio serves as an additional way to remove stimulus and lift borrowing costs."[17]

Previously, Fed policy had been to repurchase these securities upon maturity, thereby adding stimulus and lowering borrowing costs.

Q. To date, what action has the Fed taken to hike short-term interest rates this year?

A. The Fed has hiked short term interest rates seven (7) times in 2022, as shown below:[18]

Date	Increase	Level (%)
15-Dec	0.50%	4.25 – 4.50
3-Nov	0.75%	3.75 – 4.00
22-Sep	0.75%	3.00 – 3.25
28-Ju	0.75%	2.25 – 2.50
16-June	0.75 %	1.50 – 1.75
5-May	0.50 %	0.75 – 1.00
17-March	0.25 %	0.25 – 0.50

Policy rate in effect prior to first 2022 rate hike: 0.00 – 0.25

[17] Timiraos, Nick, "Fed Lifts Interest Rates by Half Point in Biggest Hike since 2000'" *wsj.com*, May 4, 2022. https://www.wsj.com/articles/fed-approves-half-point-interest-rate-rise-ratcheting-up-its-inflation-fight-11651687201

[18] Federal Open Market Committee (FOMC) Historical Archive, Target Federal Funds Rate. https://www.federalreserve.gov/monetarypolicy/openmarket.htm

As shown, the Fed's first increase (0.25%) came in March 2022, at a time when the Federal Funds Rate was at its Effective Lower Bound ("ELB"), 0.00 - 0.25 percent.[19] Since then, the Fed has raised its policy rate six additional times; twice by 50 basis points (in May and December), and four times by 75 basis points (in June, July, September, and November). The Fed's 50 basis point hike in May 2022 was the largest since 2000,[20] and 75 basis point hike in June 2022 the largest since 1994.[21] RUCO Exhibit JAC-A presents a record of changes made to the Federal Funds Rate, 2006-2022.

Q. In tightening monetary policy so aggressively, is it possible the Fed may send the economy into recession and cause the unemployment rate to rise?

A. Yes, and evidence of this can be seen when parsing the statements issued by the Federal Reserve's Federal Open Market Committee ("FOMC") following its rate hike of May 4, 2022 as compared to that of June 15, 2022. As shown below, the FOMC Statement of May 4, 2022 includes the following sentence:

> "With appropriate firming in the stance of monetary policy, the *Committee expects inflation to return to its 2 percent objective and the labor market to remain strong*."[22] (emphasis added)

In the FOMC Statement issued on June 16, 2022, however, the above sentence is missing, and replaced by another which makes no reference to a strong labor market:

---

[19] At the time of this 0.25% increase, the Federal Funds Rate had been at its ELB since March 16, 2020, a period of two years, when the Fed had lowered its policy rate by 1.00% in response to the onset of the COVID-19 pandemic.
[20] Timiraos, Nick, "Fed Lifts Interest Rates by Half Point in Biggest Hike since 2000'" *wsj.com*, May 4, 2022.
[21] Timiraos, Nick, "Fed Raises Rates by 0.75 Percentage Point, Largest Increase since 1994," *wsj.com*, June 15, 2022. https://www.wsj.com/articles/fed-raises-rates-by-0-75-percentage-point-largest-increase-since-1994-11655316170
[22] Federal Reserve FOMC Statement: Press Release, *federalreserve.gov*, May 4, 2022. https://www.federalreserve.gov/newsevents/pressreleases/monetary20220504a.htm

> "The Committee is *strongly committed to returning inflation to its 2 percent objective.*"[23]

At a press conference following the Fed's announced 0.75 percent rate hike on June 15, 2022, in response to a question as to whether the Fed might go too far in hiking interest rates to combat inflation, Fed Chair Powell responded as follows:

> "There's always a risk of going too far or going not far enough, and it's going to be a very difficult judgment to make, or maybe not, maybe it'll be really clear, but we're, and we're quite mindful of the dangers. But I will say the worst mistake we could make would be to fail, which is not an option. We have to restore price stability, we really do, because everything, it's the bedrock of the economy. If you don't have price stability, the economy's really not going to work the way it's supposed to and it won't work for people, their wages will be eaten up. So we want to get the job done."[24]

Q. What is 10-year breakeven inflation, and how is it calculated?

A. Ten (10) year breakeven inflation is a market-based measure of investor expectations of inflation over the next 10-years, computed as the difference between the current nominal yield on the 10-year Treasury Note and the current real (i.e., inflation adjusted) rate on the 10-Year Treasury Inflation-Indexed Constant Maturity Securities, or TIPS. Below is the current 10-year breakeven inflation rate, measured as a recent (i) 3-month average (October – December, 2022), and (ii) 1-month average (December, 2022):[25]

	3-Month Average (Oct. – Dec. 2022)	1-Month Average (December, 2022)
10-Year Yield – Nominal	3.83 %	3.62 %
10-Year Yield – Real	- 1.49 %	- 1.36 %
10-Year Breakeven Inflation	**2.34 %**	**2.26 %**

[23] Federal Reserve FOMC Statement: Press Release, *federalreserve.gov*, June 15, 2022. https://www.federalreserve.gov/newsevents/pressreleases/monetary20220615a.htm

[24] "Transcript of Chair Powell's Press Conference," *federalreserve.gov*, June 15, 2022 (pp. 20-21). https://www.federalreserve.gov/mediacenter/files/FOMCpresconf20220615.pdf

[25] The 10-year nominal rate and the 10-year TIPS rate are available from the U.S. Department of the Treasury. https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=realyield

Q. How do the above current (i) 2.34 percent 3-month average and (ii) 2.26 percent 1-month average projections of breakeven inflation compare to average 10-year historical inflation over the past forty years (i.e., 1982-2021)?

A. As presented in Schedule JAC-5 (Page 1), based on annual rates of inflation as measured by the Consumer Price Index ("CPI"), average inflation measured over a 10-year historical period going back to 1982 is as follows:

Historical 10-Year Period	Historical 10-Year Inflation
1982 - 1991	3.90 %
1992 - 2001	2.51 %
2002 - 2011	2.49 %
2012 - 2021	2.15 %

Projected 10-Year Period	Projected 10-year inflation
2022-2031	2.26 % - 2.34 %

As shown, 10-year projected breakeven inflation as determined by investors in the marketplace over the period, 2022-2031, is expected to exceed historical inflation in only the most recent 10-year period (i.e., 2012-2021), while remaining below that of the prior 30-year period (i.e., 1982-2011).

Q. How do investor expectations of 10-year breakeven inflation, as measured on a 1-and 3-month basis, January-December, 2022, compare to current (i.e., 2.26% - 2.34%) projections of 10-year breakeven inflation?

A. RUCO has prepared an Exhibit[26] showing 1-month and 3-month measures of 10-year breakeven inflation during the period, January-December, 2022. As shown in Exhibit JAC-B (Page 2 of 2), and as summarized below, measured on a 1-month average basis 10-year

[26] Exhibit JAC-B (Pages 1 and 2).

breakeven inflation began the year at an expected level of 2.45 percent, rose to a peak of 2.88 percent (April 2022), and ended the year at its current 2.26 percent level. On a 3-month average basis (Nov. 2021-Jan. 2022), 10-year breakeven inflation began the year at an expected level of 2.51 percent, rose to a peak of 2.81 percent (March-May, 2022), before ending the year at its current 2.34 percent level (Oct.-Dec., 2022).

	10-Year Breakeven Inflation Estimates	
	1-Month	3-Month
January 2022	2.45 %	2.51 %
Peak estimate	2.88 %	2.81 %
December 2022	2.26 %	2.34 %

Exhibit JAC-B (Page 1 of 2) provides comparable 1- and 3-month average estimates of 10-year breakeven inflation for the period, January-December, 2021. As shown, the current 2.26 percent 1-month average estimate of projected 10-year breakeven inflation is the ***lowest since February 2021*** (i.e., 2.18%), while the current 2.34 percent 3-month average estimate of projected 10-year breakeven inflation is the ***lowest since July-September 2021*** (i.e., 2.34%).

Q. Does the above noted fall in 10-year breakeven inflation from levels not seen since early-2021 suggest that investors approve of the restrictive monetary policies enacted by the Fed to combat inflation?

A. Yes, for if investors did not approve of the actions taken by the Fed, one can safely assume that yields on long-term Treasury Bonds and the 10-year breakeven inflation rate, as determined by investors in the marketplace, would have risen significantly higher from their current levels.

Q. In direct testimony,[27] Ms. Bulkley discusses 10-year breakeven inflation and, citing a 2.84 percent 10-year breakeven inflation rate measured as of March 31, 2022, states that "investors expect inflation will remain well above the Federal Reserve's 2 percent target over the next 10 years."[28] How do you respond?

A. My response is simply to say that Ms. Bulkley is mistaken, based upon current estimates of 10-year breakeven inflation—both as a 1-month (i.e., 2.26%) and 3-month average (i.e., 2.34%)—measured as of December 2022. In absolute terms, Ms. Bulkley's 2.84 percent 10-year breakeven inflation rate exceeds the current 2.34 percent 3-month average estimate by 50 basis points (2.84% - 2.34% = 0.50%), which in relative terms equates to an overstatement of 21.4% ((0.50% / 2.34%) = 21.4%). Ms. Bulkley's 2.84 percent 10-year breakeven inflation rate exceeds the current 2.26 percent 1-month average estimate by 58 basis points (2.84% - 2.26% = 0.58%), which in relative terms equates to an overstatement of 25.7% ((0.58% / 2.26%) = 25.7%).

Q. What has been the trend in interest rates over the period, 1975-2021?

A. As shown in Schedule JAC-6 (Pages 3 – 4), interest rates rose sharply to record levels during the period, 1975-1981, when inflation was high and generally rising. Interest rates declined substantially, as did inflation, during the remainder of the 1980s and throughout the 1990s. Interest rates declined further during the period, 2000-2005, and after trending slightly upward in years 2006-2008, continued on a downward path reaching levels in years 2009-2021 not previously seen since the early 1960s. In 2008, the Fed initiated an accommodative monetary policy by lowering the federal funds rate (the rate the Fed charges banks for overnight transfers of funds), and in an effort to promote increased lending and liquidity, eventually initiated a policy of quantitative easing, an unconventional monetary policy used when short-term interest rates are at or approaching zero. As a consequence, in years 2012-

[27] Bulkley Direct, pp. 19-21.
[28] Ibid, p. 20, lines 12-14.

2021, both U.S. and corporate bond yields declined to their lowest levels in more than 40 years. Beginning in December 2015, the Fed initiated a policy of gradually raising the federal funds rate, but again lowered it to its ELB in response to the COVID-19 pandemic in March 2020. As noted, beginning in March 2022 the Fed has hiked short-term interest rates seven times this year in response to rising inflation.

Q. What has been the trend of real GDP growth in the U.S. economy?

A. As shown in Schedule JAC-6 (Page 1), real GDP growth over the 10-year period, 2012-2021 has averaged 2.06 percent per annum, while over the five year period, 2017-2021 real GDP growth has averaged 1.96 percent per annum. As further shown, after experiencing negative GDP growth in 2020 (-3.4%), the U.S. economy rebounded strongly in 2021, when GDP growth reached 5.7 percent, the highest level since 1984.

Q. What is the outlook for projected real GDP growth over the 10-year period, 2023-2032?

A. The Congressional Budget Office ("CBO"), in its Budget and Economic Outlook for the period 2022-2032, projects real GDP growth of 3.8 percent in 2022, 1.78 percent for the 5-year period, 2023-2027, and 1.74 percent for the 5-year period, 2028-2032. Over the 10-year period, 2023-2032, CBO projects average annual real GDP growth of 1.76 percent. CBO's projections of average annual real GDP growth for the period, 2023-2032, are as follows:[29]

---

[29] Congressional Budget Office, "The Budget and Economic Outlook: 2022 to 2032," Table C-1 (p. 133), May 2022. https://www.cbo.gov/publication/58147#:~:text=In%20CBO's%20projections%2C%20the%20price,unemployment%20rate%20averages%203.8%20percent.

	Time Period	Annual Average Real GDP Growth
Current Year Growth	2022	3.80 %
5-year Growth	2023 - 2027	1.78 %
5-year Growth	2028 - 2032	1.74 %
10-year Growth	2023 - 2032	1.76 %

As shown, CBO projects real GDP growth to slow from 3.8 percent in 2022 to a 10-year average of 1.76 percent over the 2023–2032 period, reflecting slower growth in consumer spending and government purchases as well as the effect of trade policies on business investment.[30]

Q. What are the Fed's projections for real GDP growth in years 2022, 2023, 2024, 2025 and longer run GDP?

A. As reported in the Feds' most recent Summary of Economic Projections,[31] the current median estimate of Real GDP growth of Federal Reserve Board members in years 2022, 2023, 2024, 2025 and Longer Run are as follows:

	2022	2023	2024	2025	Longer Run
Real GDP	0.5%	0.5%	1.6%	1.8%	1.8%
September projection	0.2%	1.2%	1.7%	1.8%	1.8 %

As shown, the current median projection of Real GDP growth by Federal Reserve Board members for 2022, 0.5 percent, is higher than the September projection (0.2 percent), but the median Fed projection of Real GDP growth in 2023 has experienced a downward adjustment, from a projected 1.2 percent level in September to an updated 0.5% projected level. Median Fed projections of Real GDP growth in year 2024 declined slightly, from 1.7

[30] Ibid.
[31] Federal Reserve Bank, Summary of Economic Projections, *federalreserve.gov*, December 14, 2022. https://www.federalreserve.gov/monetarypolicy/files/fomcprojtabl20221214.pdf

percent to 1.6 percent, while projections for Real GDP growth in 2025 and the longer run remained unchanged, at 1.8 percent.[32]

Q. Given the Fed's announced intent to continue hiking short-term interest rates in an effort to bring down inflation, do the above downward adjustments to projected Real GDP growth increase the likelihood that the economy may go into recession in 2023?

A. Yes.

Q. Do economists expect the U.S. economy to go into recession in 2023?

A. Yes, for as noted by Diane Swonk, chief economist with at KPMG,[33] the Fed is trying to engineer a recession in order to fight inflation:

> "We'll have one because the Fed is trying to create one," said Swonk. "When you say growth is going to stall out to zero and the unemployment rate is going to rise ... it's clear the Fed has got a recession in its forecast but they won't say it."

Swonk is optimistic that the recession will be "a short, shallow one," stating:

> "The good news is we should be able to recover from it quickly. We do have good balance sheets, and you could get a response to lower rates once the Fed starts easing. Fed-induced recessions are not balance sheet recessions."

Q. What trends do the economic indicators suggest for common share prices?

A. As shown in Schedule JAC-6 (Pages 5 and 6), stock prices were stagnant during the high inflation/high interest rate environment of the late 1970s and early 1980s. In 1983, however, equity prices began to rise steadily, particularly as measured by the Dow Jones Industrial Average ("DJIA"), before peaking in 2007. With the onset of the Great Recession in 2008,

---

[32] Note that CBO's 3.8% projection of Real GDP growth for 2022 exceeds by 3.3% the Fed's current median 0.5% projection (3.8% - 0.5% = 3.3%).
[33] Domm, Patti, "Why Everyone Thinks a Recession is coming in 2023," *cnbc.com*, December 23, 2022. https://www.cnbc.com/2022/12/23/why-everyone-thinks-a-recession-is-coming-in-2023.html

equity prices declined sharply from their highs of 2007, reaching a low in the first quarter of 2009. Beginning in the third quarter of 2009, equity prices again began to rise, eventually recovering the losses sustained as a consequence of the "crash" in 2008 and, as evidenced by the performance of the DJIA, the S&P 500 Composite Index ("S&P 500"), and the NASDAQ Composite Index ("NASDAQ"), went on to reach new all-time highs in each year during the period, 2013-2021. Due to rising inflation, each of these three major stock indices experienced a correction of more than 20.0 percent in mid-2022, which is suggestive of a bear market.[34] While all three have since recovered from their lows of earlier this year, each remains well off their all-time highs of November 2021.

Q. What conclusions can be drawn from the above discussion of economic and financial conditions as they relate to the cost of capital?

A. As previously discussed, after an extended period characterized by low interest rates, low inflation, low unemployment and rising stock prices, it appears that economic growth as measured by Real GDP may experience a near term decline going forward. As noted earlier, Fed Chairman Powell has characterized '*price stability*' as the '*bedrock of the economy*,' and something which must be '*restored*.' Thus, it appears the Fed is prepared to continue hiking short-term interest rates in order to '*get the job done*.' As evidenced by the decline in 10-year breakeven inflation, investors have responded favorably to the Fed's aggressive monetary policies, believing the action taken by the Fed to be appropriate in fighting inflation. Economists generally agree that the domestic economy will go into recession in 2023; should that happen inflationary pressures would be expected to mitigate, allowing the Fed to reverse course from its current restrictive monetary policy stance. These developments portend to a more accommodative monetary policy and lower capital costs, including the cost of common equity.

---

[34] "Wall Street is in a Bear Market. Here's what that Means for Your Money,' *cbsnews.com* (June 14, 2022) https://www.cbsnews.com/news/bear-market-2022-stock-market-wall-street-money/

V. CAPITAL STRUCTURE AND COST OF DEBT

Q. What capital structure does TEP propose be used for purposes of setting rates in this proceeding?

A. In its Application, the Company proposes a capital structure comprised of 45.68 percent long-term debt, and 54.32 percent common equity.[35]

Q. How does the Company's proposed capital structure compare to the sample average capital structure of RUCO's proxy group of companies?

A. As shown in Schedule JAC-5 (Page 7), the sample average capital structure of RUCO's proxy group of companies is comprised of 52.89 percent long-term debt and 47.11 percent equity.[36] Thus, the Company's proposed capital structure is less highly leveraged than the sample average capital structure of RUCO's proxy group of companies.

Q. What capital structure does RUCO recommend for TEP in this proceeding?

A. As shown in Schedule JAC-1, RUCO adopts the Company's proposed capital structure comprised of 45.68 percent long-term debt and 54.32 percent common equity.

Q. What is the Company's proposed cost of long-term debt?

A. As shown in Schedule D-1, the Company proposes a 3.82 percent cost of long-term debt.

Q. What is RUCO's proposed cost of long-term debt in this proceeding?

A. As shown in Schedule JAC-1, RUCO adopts the Company's proposed 3.82 percent cost of long-term debt.

---

[35] *See* Pritz Direct, p. 9; and Schedule D-1, (Page 1 of 2).

[36] As shown in Schedule JAC-5 (Page 7), RUCO's sample average 47.11 percent common equity ratio represents an average of the (i) 5-year historical (2017-2021) and (ii) 5-year projected (2022-2026) common equity ratios for RUCO's proxy group of companies ((48.1% + 46.1%) / 2 = 47.11%).

VI. SELECTION OF PROXY GROUP

Q. Was RUCO able to directly estimate the cost of common equity for the Company?

A. No. The common stock of TEP is not publicly-traded, and thus it is not possible to directly estimate the Company's cost of common equity. Therefore, RUCO employed a proxy group of publicly-traded electric utility companies to indirectly estimate the Company's cost of equity ("COE") utilizing financial market data available for each sample company.

Q. What publicly-traded electric utility companies has RUCO selected for inclusion in its proxy group?

A. For purposes of its analysis, RUCO adopts the same proxy group of companies used by Company witness, Ms. Bulkley. RUCO's proxy group is comprised of the following fifteen (15) publicly-traded electric utility companies: ALLETE, Inc. (Ticker: ALE); Allient Energy Corporation (Ticker: LNT); Ameren Corporation (Ticker: AEE); American Electric Power Company, Inc. (Ticker: AEP); Duke Energy Corporation (Ticker: DUK); Entergy Corporation (Ticker: ETR); Evergy, Inc. (Ticker: EVRG); IDACORP, Inc. (Ticker: IDA); NextEra Energy, Inc. (Ticker: NEE); NorthWestern Corporation (Ticker: NWE); OGE Energy Corp. (Ticker: OGE); Otter Tail Corporation (Ticker: OTTR); Portland General Electric Co. (Ticker: POR); Southern Company (Ticker: SO); and Xcel Energy, Inc. (Ticker: XEL). Each of these fifteen electric utilities are followed by *The Value Line Investment Survey*. Attachment 2 contains the most recent *Value Line* quarterly update for each of RUCO's fifteen proxy companies.

VII. DCF ANALYSIS

Q. What is the theory and methodological basis of the DCF model?

A. The DCF model is one of the oldest and most commonly used market-based models for estimating the COE for public utilities, and the only one which intrinsically takes into consideration the price investors are willing to pay for a given unit of return. The DCF is based on the "dividend discount model" of financial theory, which maintains that the value (price) of any security or commodity is the discounted present value of all future cash flows.

The most common variant of the DCF model assumes that dividends are expected to grow at a constant rate, and the COE is computed using the following formula:

$$K = \frac{D}{P} + g$$

Where: K = discount rate (cost of equity)

P_0 = current stock price

D_0 = current annualized dividend

D1 = expected dividend

D0 / P0 = current dividend yield

D1 / P0 = expected dividend yield

g = expected constant dividend growth rate

This formula essentially recognizes that the return expected, or required, by investors is comprised of two factors: the dividend yield (current income) and expected growth in dividends (future income).

Q. Please explain how RUCO employed the DCF model.

A. For purposes of its analysis, RUCO employs the constant growth DCF model. In doing so, RUCO combines the current annualized dividend (D_0) for each sample company with measures of (i) 5-year historic (i.e., 2017-2021) dividend growth, and (ii) 5-year projected (i.e., 2022-2026) dividend growth, thereby obtaining for each sample company a measure of next year's expected dividend (D_1).

Q. How did RUCO derive the dividend yield component of the DCF equation?

A. Several different methods can be used to compute the dividend yield component in the constant growth DCF model. However, for purposes of its analysis, RUCO employs the Gordon quarterly compounding method to compute the dividend yield component, as it gives recognition to the timing of dividend payments and dividend increases. The Gordon quarterly compounding method is expressed as follows:

$$Yield = \frac{D_0(1 + 0.5g)}{P_0}$$

The current (P_o) stock price represents the average stock price for each proxy company over the most recent 3-month period (September – November 2022). The current (D_o) dividend is the current annualized dividend rate for each proxy company. Because the expected (D_1) dividend represents the quantity, [D_0 * (1 + .05g)], the above equation is representative of the expected dividend yield, (D_1 / P_o).

Q. How does RUCO estimate the dividend growth (g) component of the DCF equation?

A. In estimating the dividend growth (g) rate in its DCF analysis, for each sample company RUCO gives consideration to the following two indicators of dividend growth:

1. Five-year (2017-2021) compound annual historical dividend per share ("DPS") growth, as reported by *Value Line*; and

2. Five-year (2022-2026) compound annual projected dividend per share ("DPS") growth, as reported by *Value Line*;

RUCO believes historical and projected measures of DPS growth to be representative of investor expectations of dividend growth for each of its proxy group companies. Additionally, *Value Line's* historic and projected measures of dividend growth is information that investors evaluate and take into consideration when making an investment decision.

Q. Please describe RUCO's DCF calculations.

A. RUCO's DCF analysis is presented in Schedule JAC-3 (Pages 1 and 2). Schedule JAC-3 (Page 1) presents the current indicated annual dividend (D_0) paid on a per share basis by each of RUCO's proxy companies, and a calculation of the current dividend yield (D_0 / P_0) for each proxy company based upon a recent 3-month average stock price (September – November, 2022). For each proxy company, Schedule JAC-3 (Page 2) presents (i) *Value Line's* 5-year compound annual historical and projected DPS growth estimates, (ii) a combined average DPS growth estimate, (iii) a calculation of the expected dividend yield (D_1 / P_0), and (iv) RUCO's DCF derived equity cost rates for each proxy company.

Q. What does RUCO conclude from its DCF cost of equity estimation analyses?

A. As shown in Schedule JAC-3 (Page 2), the DCF equity cost rates obtained for RUCO's proxy group fall within the range, 9.19 percent to 9.24 percent (midpoint 9.21 percent), as shown below.

	Constant Growth DCF Estimates
Mean	9.19 %
Median	9.24 %
Average of Mean and Median	9.21 %

RUCO concludes that the 9.21 percent (average of mean and median) estimate represents the current DCF-derived cost of equity for the proxy group. Accordingly, RUCO adopts a DCF-derived cost of equity of 9.21 percent for the Company, which is based on the midpoint of the DCF range.

VIII. CAPM ANALYSIS

Q. Please describe the theory and methodological basis of the CAPM.

A. Developed in the 1960s and 1970s as an extension of modern portfolio theory, which studies the relationships among risk, diversification, and expected returns, the CAPM describes the relationship between a security's investment risk and its market rate of return.[37] The CAPM employs beta as a measure of relative risk (i.e., volatility) between a given equity security and the market as a whole.

Q. Please describe the CAPM.

A. The CAPM is a market-based model founded on the principle that investors expect higher returns for incurring additional risk.[38] The CAPM estimates this expected return. Using the CAPM to estimate the cost of equity of a regulated utility is consistent with the legal standards governing the fair rate of return. The U.S. Supreme Court has recognized that "the amount of risk in the business is a most important factor" in determining the allowed rate of return,[39] and that "the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks."[40] The CAPM is a useful model because it directly considers the amount of risk inherent in a business. Unlike the DCF Model, the CAPM directly measures the most important component of a fair rate of return analysis – risk.

Q. How is the CAPM derived?

A. The general form of the CAPM is:

[37] The CAPM makes the following assumptions: 1) single holding period; 2) perfect and competitive securities market; 3) no transaction costs; 4) no restrictions on short selling or borrowing; 5) the existence of a risk-free rate; and 6) homogeneous expectations.
[38] William F. Sharpe, A Simplified Model for Portfolio Analysis 277–93 (Management Science IX 1963).
[39] Wilcox, 212 U.S. at 48.
[40] Hope Natural Gas Co., 320 U.S. at 603.

$$K = R_f + \beta (R_m - R_f)$$

Where: K = *cost of equity*

Rf = risk free rate

Rm = return on market

β = beta

$R_m - R_f$ = *market risk premium*

The CAPM is a variant of the Risk Premium ("RP") method. However, the CAPM is generally superior to the simple RP method because it provides for company-specific recognition of risk (i.e., beta), whereas the simple RP method assumes the same cost of equity for all companies exhibiting similar bond ratings or other characteristics.

Q. Please identify the strengths of the CAPM.

A. The CAPM is cited as having the following strengths (1) it is market-based; (2) it is based on the concept of risk and return; (3) it is company specific; (4) it has widespread use as it recognizes that investors can and do diversify; (5) it is highly structured and easy to apply when using the assumptions of the model; (6) the model is formulistic and the data used in the computation is readily available; (7) it is a forward looking concept; and (8) it is a method for converting changes in interest rates to the COE.

Q. What risk-free (R_f) rate does RUCO use in its CAPM analysis?

A. For purposes of its CAPM analysis, RUCO employs a risk-free rate of 3.98 percent. RUCO's risk-free rate represents the 3-month average yield on 20- and 30-year long-term Treasury Bonds, measured over the 3-month period, September – November, 2022. The calculation of RUCO's risk-free rate is presented in Schedule JAC-4 (Page 1).

Q. Is it customary to use the yield on U.S. Treasury securities as the risk-free (R_f) rate in the CAPM?

A. Yes, because debt securities issued by the United States Department of the Treasury are considered to be free of default risk. Two general types of U.S. Treasury securities are most often used as the risk-free *(Rf)* rate component, short-term U.S. Treasury bills and long-term U.S. Treasury bonds. As noted, RUCO employs yields on 20-year and 30-year long-term Treasury bonds as a proxy for the risk-free rate in the CAPM.

Q. Did RUCO consider use of a forecasted long-term Treasury bond rate as the risk-free rate to be used in its CAPM analysis?

A. No. The appropriate interest rate to be used in the CAPM is the current rate borne by investors in the marketplace. Use of a forecasted risk-free rate overstates cost of equity estimates derived from the CAPM. Use of a current, or recent average, long-term Treasury rate is reflective of investor's expectations, and as such is the appropriate risk-free rate to be used in the CAPM.

Q. What is beta, and what beta coefficients does RUCO employ in its CAPM analysis?

A. Beta is a measure of risk (i.e., volatility) of a particular stock relative to the market as a whole. The overall market is assumed to have a beta of 1.0; thus, companies having betas less than 1.0 are considered less risky than the market, whereas companies with betas greater than 1.0 are considered more risky than the market. As regulated entities which have been granted natural monopoly status, regulated public utilities are considered less risky than the market and typically have betas less than 1.0. For purposes of its analysis, RUCO utilizes the most recent beta reported by *Value Line* for each of its sample companies. As shown in Schedule JAC-4 (Page 1), the sample average beta of RUCO's proxy group is 0.87.

Q. How does RUCO estimate the market risk premium (R_m-R_f) component?

A. The market risk premium component (R_m-R_f) represents the investor-expected premium associated with common stock ownership above that of the risk-free rate, or government bonds. For purposes of its analysis, in estimating the market risk premium RUCO gives consideration to the following three measures of the market risk premium:

(1) a 6.3 percent Arithmetic Mean estimate of realized equity returns on the S&P 500 above that of returns on long-term government bonds, measured over the period, 1926-2021;
(2) a 5.0 percent Geometric Mean estimate of realized equity returns on the S&P 500 above that of returns on long-term government bonds, measured over the period, 1926-2021; and
(3) a 7.69 percent Arithmetic Mean estimate of differential returns on equity for the S&P 500 above that of returns on 20-year government bonds, measured over the period, 1978-2021.[41]

As shown in Schedule JAC-4 (Page 3 of 4), and as summarized below, RUCO estimates the current market risk premium to be 6.33 percent.

Arithmetic Mean (1926-2021)	6.30 %
Geometric Mean (1926-2021)	5.00 %
Arithmetic Mean (1978-2021)	7.69 %
Market Risk Premium	6.33 %

Q. As noted earlier, RUCO adopts the Company's proposed capital structure and employs the same Proxy Group as Company witness, Ms. Bulkley. Is TEP's proposed capital structure comparable in risk to that of the Proxy Group capital structure?

A. No, it is not. The debt ratio in the Company's proposed capital structure is 45.68 percent, while as shown in Schedule JAC-5 (Page 7 of 7) the sample average debt ratio in the Proxy Group is 52.89 percent (100.00% – 47.11% = 52.89%). Because the Proxy Group debt ratio

[41] The computation of RUCO's 7.69 percent market risk premium is presented in Schedule JAC-4 (Page 2 of 2).

exceeds that proposed by the Company, the Proxy Group is more highly leveraged and, thus, has greater exposure to financial risk than does TEP. Equity investors require compensation for exposure to financial risk, and for this reason it is necessary to make a downward adjustment to the equity cost rate in recognition of TEP having less exposure to financial risk than the Proxy Group. RUCO makes this downward equity cost adjustment by means of a Hamada risk adjustment.

Q. What is the premise of the Hamada formula?

A. The Hamada formula can be used to analyze changes in a firm's cost of capital as it adds or reduces financial leverage, or debt, in its capital structure by starting with an "unlevered" beta and then "relevering" the beta at different debt ratios. As leverage increases, equity investors bear increasing amounts of risk, leading to higher betas. Before the effects of financial leverage can be accounted for, however, the effects of leverage must first be removed, which is accomplished through the Hamada formula. The Hamada formula to unlever beta is stated as follows:

Hamada Formula

$$\beta_U = \frac{\beta_L}{\left[1 + (1 - T_c)\left(\frac{D}{E}\right)\right]}$$

where: β_U = unlevered beta (or "asset" beta)

β_L = average levered beta of proxy group

T_C = corporate tax rate

D = book value of debt

E = book value of equity

Using this equation, the beta for the firm can be unlevered, and then "relevered" based on various debt ratios (by rearranging this equation to solve for β_L).

Q. Please explain the methodology employed by RUCO to make this downward equity cost adjustment.

A. RUCO's Hamada risk adjustment is presented in Schedule JAC-4 (Page 4 of 4). As shown, Lines 1-8 present the inputs and steps taken to "unlever" the 0.87 Proxy Group beta to a level of 0.47, and Lines 9-12 present the steps taken to "relever" beta at different debt levels for purposes of modeling. As shown, utilizing the Hamada formula a downward adjustment to the 9.51 percent CAPM-derived equity cost rate at the Proxy Group Debt Ratio (i.e., 52.89%) equates to a risk-adjusted 8.88 percent CAPM equity cost rate at the Company proposed Debt Ratio (i.e., 45.68%).

Q. In Direct testimony does Ms. Bulkley state that she believes her Proxy Group companies are "comparable" to TEP?

A. Not exactly. Ms. Bulkley characterizes the companies in her Proxy Group as being, "generally comparable to TEP."[42]

Q. In Direct testimony, does Ms. Bulkley acknowledge that TEP has less exposure to financial risk than do her Proxy Group companies?

A. No, to the contrary, Ms. Bulkley states that TEP faces greater exposure to financial risk than her Proxy Group companies.[43]

[42] Bulkley Direct, p. 5.
[43] Bulkley Direct, p. 6, line 18.

Q. What did RUCO conclude the overall CAPM cost of equity to be?

A. RUCO's cost of common equity recommendations are presented in Schedule JAC-2 (Page 1 of 1). As shown, RUCO gives recognition to both the 9.51 percent (CAPM at Proxy Debt Ratio) and the 8.88 percent Hamada CAPM (at Company-proposed Debt Ratio). Thus, RUCO's CAPM estimates lie within the range, 8.88% to 9.51%, for a midpoint estimate of 9.20 percent.

IX. RUCO RESPONSE TO COMPANY'S COST OF CAPITAL WITNESS MS. ANN E. BULKLEY

Q. Have you reviewed the cost of capital testimony of TEP witness, Ms. Ann E. Bulkley?

A. Yes, I have.

Q. Briefly summarize Ms. Bulkley's cost of equity estimation methodology and recommendations.

A. Based on her analyses, Ms. Bulkley determined that TEP's cost of equity lies within a range of 7.98 percent to 11.89 percent, and recommends that TEP be authorized a 10.25 percent ROE in this proceeding. Ms. Bulkley obtains cost of equity estimates for her proxy group of companies from (i) the Constant Growth DCF model, (ii) the CAPM, (iii) the ECAPM, and (iv) a Bond Yield Plus Risk Premium methodology. The following briefly summarizes the range of estimates obtained from each of the cost of equity estimation models employed by Ms. Bulkley:

	Low	High	Midpoint
Constant Growth DCF	7.98 %	10.33 %	9.16 %
CAPM	10.04 %	11.63 %	10.84 %
ECAPM	10.70 %	11.89 %	11.30 %
Bond Yield Plus Risk Premium	9.68 %	10.22 %	9.95 %
Average with ECAPM	9.60 %	11.41 %	10.31 %
Average without ECAPM	9.23 %	10.73 %	9.98 %

As shown, the highest equity cost estimates obtained by Ms. Bulkley were from the ECAPM. By excluding the ECAPM results obtained by Ms. Bulkley, the average low falls by 37 basis points (9.60% - 9.23% = 0.37%), the average high falls by 68 basis points (11.41% - 10.73% = 0.68%), and the average midpoint by 33 basis points (10.31% - 9.98% = 0.33%).

Q. What is the ECAPM formula, and how does it differ from the CAPM formula?

A. As shown below, the CAPM computes the cost of equity (*K*) by adding the risk-free rate (R_f) to the quantity, beta coefficient (β) x market risk premium $(Rm - Rf)$:

$$K = Rf + \beta(Rm - Rf)$$

In contrast, the ECAPM formula is a modification to the CAPM, assigning a 75.0 percent weight to the results obtained from the CAPM, and adjusting the CAPM result by weighting 25.0 percent of the ROE result as if the beta of the proxy group was 1.0, as shown below:

$$K = Rf + 0.75\beta(Rm - Rf) + 0.25(Rm - Rf)$$

Effectively, the above adjustment made to the CAPM is equivalent to replacing 25% of Ms. Bulkley's proxy group with companies having the same risk (beta of 1.0) as the market.

Regulated utilities such as TEP are less risky than competitive firms having a 1.0 market beta, and the ECAPM results obtained by Ms. Bulkley compensate shareholders with higher returns that reflect non-utility risk.

Q. In support of her ECAPM analysis, Ms. Bulkley states that "the ECAPM is not redundant with the use of adjusted Betas."[44] Does RUCO agree with Ms. Bulkley on this point?

A. No. In her CAPM and ECAPM analyses, Ms. Bulkley utilizes upwardly adjusted betas from *Value Line* and *Bloomberg*. While use of upwardly adjusted betas in the CAPM is appropriate, their use in the ECAPM is inappropriate as they further serve to overstate the cost of equity, particularly when considering that the 1.0 market beta is assigned a 25.00 percent weight in her ECAPM analysis. As noted, Ms. Bulkley obtained her highest equity cost estimates from the ECAPM, and a comparison of the midpoint estimates obtained from Ms. Bulkley's CAPM (10.84%) and ECAPM (11.30%) analysis shows that the ECAPM midpoint exceeded that of the CAPM midpoint by 46 basis points (11.30% - 10.84% = 0.46%). While the lion's share of this cost differential is attributable to the ECAPM assigning a 25.00 percent weight to the 1.0 market beta, a portion is attributable to use of higher, upwardly adjusted betas assigned a 75.00 percent weight, thereby making their use in the ECAPM, "redundant."

Q. To what authority does Ms. Bulkley cite as support for employing estimates obtained from the ECAPM?

A. Ms. Bulkley cites a book authored by Dr. Roger A. Morin, entitled <u>New Regulatory Finance</u>.[45]

[44] Bulkley Direct, p. 50.
[45] Bulkley Direct, p. 50, Footnote 61. The citation reads: Roger A. Morin, New Regulatory Finance, Public Utilities Reports, Inc., 2006, at 189.

Q. In the above cited book, is there reason to believe that the ECAPM is not a mainstream model generally embraced by the financial community?

A. Yes, as Dr. Morin discusses the ECAPM in a chapter entitled, "Alternative Asset Pricing Models," suggesting that he was aware it was not a mainstream method.

XI. FAIR VALUE RATE OF RETURN

Q. What Fair Value Rate of Return ("FVROR") does TEP propose in this proceeding?

A. The Company proposes a FVROR of 5.20 percent. The FVROR proposed by TEP incorporates a 0.66 percent Fair Value Increment ("FVI") cost rate, as recommended by Ms. Bulkley.[46]

Q. Does RUCO believe the Company should be authorized a return on the FVI in this proceeding?

A. No. It is RUCO's position that a return on the FVI is inappropriate, as it provides shareholders with a return on non-investor supplied capital. To the extent the Commission believes it appropriate to provide for a return on TEP's FVI as a policy matter, it is RUCO's position that a downward adjustment be made to the Company's authorized ROE in recognition that a return on FVI mitigates risk. As support, RUCO cites to Commission Decision No. 77956,[47] issued in a recent Arizona Water Company rate docket, wherein the Commission ruled as follows:

> "Based on the circumstances in this case, we find that a return on FVI of 0.20 percent is appropriate and we will adopt it. By allowing a return on FVI, AWC is provided with additional revenue and cash flow which reduces the Company's overall risk. As a result, we find it reasonable and appropriate to lower AWC's COE by 20 basis points, to 9.00 percent, to reflect the reduced risk afforded by the return on FVI."

---

[46] Bulkley Direct, p. 3.
[47] Decision No. 77956 (dated April 15, 2021) issued in Docket No. W-01445A-19-0278.

Q. What FVROR does RUCO recommend for TEP in this proceeding?

A. As shown in Schedule JAC-1 (Page 2 of 2), RUCO recommends a FVROR of 4.66 percent, based upon a 0.00 percent FVI cost rate.

Q. Did RUCO compute a fair value increment ("FVI") cost rate for the Company?

A. No.

XII. CONCLUSION AND RECOMMENDATIONS

Q. Please summarize RUCO's cost of capital recommendations in this proceeding.

A. RUCO recommends that the Commission adopt the following:

1) A capital structure comprised of 45.68 percent long-term debt and 54.32 percent common equity;
2) A 3.82 percent cost of long-term debt;
3) A cost of common equity of 9.20 percent;
4) An overall rate of return of 6.74 percent;
5) A fair value increment cost rate of 0.0 percent; and
6) A fair value rate of return of 4.66 percent.

Q. Does this conclude your direct testimony?

A. Yes, it does.

ATTACHMENT 1

John A. Cassidy   Regulatory Experience

Attachment 1

John A. Cassidy, CRRA

EDUCATION

Arizona State University -- Master of Business Administration-Finance (May 1987)

University of Arizona -- Master of Library Science (August 1980)

Arizona State University -- B.A. History, Latin American Studies (May 1976)

EXPERIENCE

Public Utilities Analyst V – Residential Utility Consumer Office (RUCO), Phoenix, AZ (July 2015-Present)

Public Utilities Analyst III -- Arizona Corporation Commission, Phoenix, AZ (March 2013-July 2015)

Public Utilities Analyst II -- Arizona Corporation Commission, Phoenix, AZ (May 2012-March 2013)

Public Utility Consultant -- Arizona Corporation Commission, Phoenix, AZ(Jan. 2012-May 2012)

Regulatory Utility Consultant – Self-Employed, Tempe, AZ (2009-2010)

- Assisted in the preparation of testimony filed by the Residential Utility Consumer Office (RUCO) in the Litchfield Park W/WW rate case (Docket No. SW-01428A-09-0103, et al)

Regulatory Utility Consultant – Self-Employed, Tempe, AZ (2007-2008)

- Filed formal cost of capital testimony/schedules on behalf of intervener, Anthem Town Council, and testified at evidentiary hearing in the Arizona-American Water Co., Anthem Water and Anthem/Agua Fria WW rate case (Docket No. WS-01303A-06-0403)

Utilities Auditor II -- Arizona Corporation Commission, Phoenix, AZ (Aug. 1993-Nov. 1997)

PROFESSIONAL DEVELOPMENT

Certified Rate of Return Analyst (CRRA) (May 2016)

National Association of State Utility Consumer Advocates (NASUCA), Portland OR (June 2020)

Annual Regulatory Studies Program ("Camp NARUC"), Institute of Public Utilities, Michigan State University, East Lansing, MI (August 4-15, 2014)

Annual Financial Forum, Society of Utility and Regulatory Financial Analysts (SURFA) Indianapolis, IN (April 2013 and April 2016); New Orleans, LA (April 2017 and April 2019); Richmond, VA (April 2022)

NARUC Utility Rate School, San Diego, CA (May 13-17, 2013)

HONORS

CPA Candidate - Passed the CPA exam (1997), but opted not to pursue certification
Beta Gamma Sigma - National Honor Society in Business Administration

Rate Dockets Testified - Cost of Capital:

Tucson Electric Power Company	Docket No. E-01933A-22-0107
Liberty Utilities (Gold Canyon Sewer)	Docket Nos. SW-02519A-21-0326, et al.
Southwest Gas Corporation	Docket No. G-01551A-21-0368
EPCOR Water Arizona - San Tan	Docket No. WS-02987A-20-0025
Global Water Utilities	Docket Nos. SW-20445A-20-0214, et al.
EPCOR Water Arizona, Inc.	Docket No. WS-01303A-20-0177
Arizona Water Company – Western Group	Docket No. W-01445A-19-0278
Arizona Public Service Company	Docket No. E-01345A-19-0236
Liberty Utilities (Black Mountain Sewer)	Docket No. SW-02361A-19-0139
Southwest Gas Corporation	Docket No. G-01551A-19-0055
Tucson Electric Power Company	Docket No. E-01933A-19-0028
Arizona Water Company – Northern Group	Docket No. W-01445A-18-0164
EPCOR Water Arizona, Inc.	Docket No. WS-01303A-17-0257, et al.
Liberty Utilities (Litchfield Park Service Co.)	Docket No. SW-01428A-17-0058, et al.
Pima Water Company	Docket No. W-02199A-16-0421, et al.
Arizona Public Service Company	Docket No. E-01345A-16-0036
EPCOR Water Arizona, Inc.	Docket No. WS-01303A-16-0145
Southwest Gas Corporation	Docket No. G-01551A-16-0107
Liberty Utilities (Bella Vista W / Rio Rico W/WW)	Docket Nos. W-02465A-15-0367, et al.
Arizona Water Company	Docket No. W-01445A-15-0277
Liberty Utilities (Black Mountain Sewer)	Docket Nos. SW-02361A-15-0206, et al.
Quail Creek Water Company	Docket No. W-02514A-14-0343
EPCOR Water Arizona	Docket No. WS-01303A-14-0010
Utility Source, L.L.C.	Docket No. WS-04235A-13-0331
Verde Santa Fe Wastewater Company	Docket No. SW-03437A-13-0292
Chaparral City Water Company	Docket No. W-02113A-13-0118
Payson Water Company	Docket No. W-03514A-13-0111
Lago Del Oro Water Company	Docket No. W-01944A-13-0215
Las Quintas Serenas Water Company	Docket No. W-01583A-13-0117

Litchfield Park Service Company	Docket Nos. SW-01428A-13-0042, et al.
Adaman Mutual Water Company	Docket No. W-01997A-12-0501
Global Water Utilities	Docket Nos. W-01212A-12-0309, et al.
New River Utility Company	Docket No. W-01737A-12-0478
Arizona Water Company	Docket No. W-01445A-12-0348
Far West Water & Sewer, Inc.	Docket No. WS-03478A-12-0307
Cordes Lakes Water Company	Docket No. W-02060A-12-0356
Rio Rico Utilities, Inc.	Docket No. WS-02676A-12-0196
Ray Water Company	Docket No. W-01380A-12-0254
Vail Water Company	Docket No. W-01651B-12-0339
Valley Water Company	Docket No. W-01412A-12-0195
Arizona Water Company	Docket No. W-01445A-11-0310
Pima Utility Company	Docket Nos. W-02199A-11-0329, et al.

Rate Dockets Testified - Revenue Requirement/Rate Design:

Pima Water Company	Docket No. W-02199A-16-0421, et al.
Arizona Water Company	Docket No. W-01445A-15-0277
Quail Creek Water Company	Docket No. W-02514A-14-0343
Beaver Dam Water Company	Docket No. W-03067A-12-0232
Eden Water Company	Docket No. W-02068A-11-0471
Great Prairie Oasis, dba Sunland Water Co.	Docket No. W-04015A-12-0051

Financing Dockets - Responsible for ACC Staff Report:

Arizona Public Service Company	Docket No. E-01345A-11-0423
Tucson Electric Power Company	Docket No. E-01933A-12-0176
Chaparral City Water Company	Docket No. W-02113A-13-0047
Payson Water Company	Docket No. W-03514A-13-0142
Lago Del Oro Water Company	Docket No. W-01944A-13-0242
Duncan Valley Electric Cooperative, Inc.	Docket No. E-01703A-13-0272
Sulphur Springs Valley Electric Cooperative, Inc.	Docket No. E-01575A-12-0457

Trico Electric Cooperative, Inc.	Docket No. E-01461A-12-0056
Great Prairie Oasis, dba Sunland Water Co.	Docket No. W-04015A-12-0050
Columbus Electric Cooperative, Inc.	Docket No. E-01851A-11-0415
Pima Utility Company	Docket Nos. W-02199A-11-0403, et al.

ATTACHMENT 2

Value Line Updates   RUCO Proxy Group

ALLETE NYSE-ALE

RECENT PRICE 66.34 | P/E RATIO 17.7 (Trailing: 18.0 Median: 19.0) | RELATIVE P/E RATIO 1.09 | DIV'D YLD 3.9% | VALUE LINE

TIMELINESS	4 Lowered 11/18/22
SAFETY	2 New 10/1/04
TECHNICAL	5 Lowered 12/9/22
BETA .90 (1.00 = Market)	

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$45-$80	$63 (-5%)

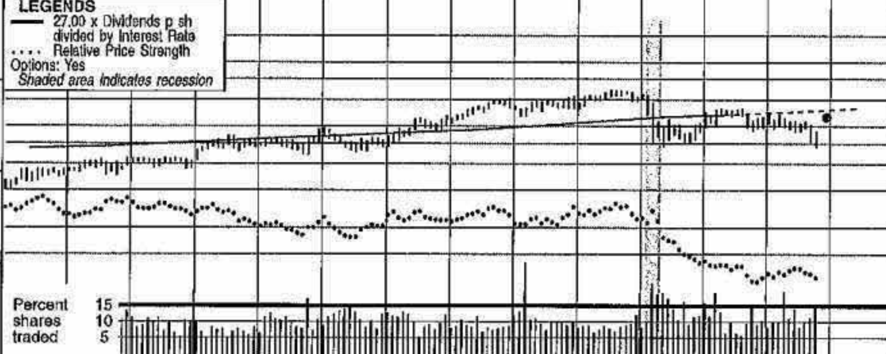
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	95	(+45%)	13%
Low	70	(+5%)	6%

Institutional Decisions

	1Q2022	2Q2022	3Q2022
to Buy	139	172	134
to Sell	131	103	130
Hld's(000)	39713	44326	44590

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	42.5	42.7	54.1	58.0	59.7	66.9	81.2	82.8	88.6	84.7	73.1	68.6
Low:	35.1	37.7	41.4	44.2	45.3	48.3	61.6	66.6	72.5	48.2	56.8	47.8



Target Price Range 2025 | 2026 | 2027

% TOT. RETURN 10/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-4.7	-13.4
3 yr.	-27.0	35.8
5 yr.	-15.0	45.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
25.23	27.33	24.57	21.57	25.34	24.75	24.40	24.60	24.77	30.27	27.01	27.78	29.10	23.99	22.44	26.68	*27.20*	*27.60*	Revenues per sh	*29.50*
4.14	4.42	4.23	3.57	4.35	4.91	5.01	5.35	5.68	6.79	7.08	6.59	7.37	7.24	7.52	7.54	*8.00*	*8.50*	"Cash Flow" per sh	*9.75*
2.77	3.08	2.82	1.89	2.19	2.65	2.58	2.63	2.90	3.38	3.14	3.13	3.38	3.33	3.35	3.23	*3.75*	*3.95*	Earnings per sh A	*4.75*
1.45	1.64	1.72	1.76	1.76	1.78	1.84	1.90	1.96	2.02	2.08	2.14	2.24	2.35	2.47	2.52	*2.60*	*2.70*	Div'd Decl'd per sh B ■ †	*3.00*
3.37	6.82	9.24	9.05	6.95	6.38	10.30	7.93	12.48	5.84	5.35	4.08	6.07	11.55	13.78	8.90	*3.70*	*5.95*	Cap'l Spending per sh	*7.25*
21.90	24.11	25.37	26.41	27.26	28.78	30.48	32.44	35.06	37.07	38.17	40.47	41.86	43.17	44.04	45.36	*47.00*	*49.10*	Book Value per sh C	*54.00*
30.40	30.80	32.60	35.20	35.80	37.50	39.40	41.40	45.90	49.10	49.60	51.10	51.50	51.70	52.10	53.20	*57.00*	*58.00*	Common Shs Outst'g D	*61.00*
16.5	14.8	13.9	16.1	16.0	14.7	15.9	18.6	17.2	15.1	18.6	23.0	22.2	24.7	18.3	20.6	*Bold figures are*		Avg Ann'l P/E Ratio	*17.0*
.89	.79	.84	1.07	1.02	.92	1.01	1.05	.91	.76	.98	1.16	1.20	1.32	.94	1.10	*Value Line*		Relative P/E Ratio	*.95*
3.2%	3.6%	4.4%	5.8%	5.0%	4.6%	4.5%	3.9%	3.9%	4.0%	3.6%	3.0%	3.0%	2.9%	4.0%	3.8%	*estimates*		Avg Ann'l Div'd Yield	*3.7%*

CAPITAL STRUCTURE as of 9/30/22
Total Debt $2043.7 mill. **Due in 5 Yrs** $390.7 mill.
LT Debt $1653.0 mill. **LT Interest** $65.9 mill.
(LT interest earned: 2.7x)

Leases, Uncapitalized Annual rentals $5.1 mill.

Pension Assets-12/21 $745.7 mill.
Oblig $911.7 mill.

Pfd Stock None

Common Stock 57,161,878 shs.

MARKET CAP: $3.8 billion (Mid Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
961.2	1018.4	1136.8	1486.4	1339.7	1419.3	1498.6	1240.5	1169.1	1419.2	*1550*	*1600*	Revenues ($mill)	*1800*
97.1	104.7	124.8	163.4	155.3	159.2	174.1	172.4	174.2	169.2	*215*	*230*	Net Profit ($mill)	*290*
28.1%	21.5%	22.6%	19.4%	11.3%	14.8%	--	--	NMF	NMF	*NMF*	*NMF*	Income Tax Rate	*NMF*
5.3%	4.4%	6.3%	2.0%	1.4%	.8%	.7%	1.3%	1.1%	1.5%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*1.0%*
43.7%	44.6%	44.2%	46.3%	42.0%	41.0%	39.9%	38.6%	41.0%	42.2%	*39.5%*	*39.5%*	Long-Term Debt Ratio	*40.5%*
56.3%	55.4%	55.8%	53.7%	58.0%	59.0%	60.1%	61.4%	59.0%	57.8%	*60.5%*	*60.5%*	Common Equity Ratio	*59.5%*
2134.6	2425.9	2882.2	3388.9	3263.4	3507.4	3584.3	3632.8	3887.8	4176.3	*4465*	*4700*	Total Capital ($mill)	*5550*
2347.6	2576.5	3286.4	3669.1	3741.2	3822.4	3904.4	4377.0	4840.8	5100.2	*5215*	*5300*	Net Plant ($mill)	*5675*
5.6%	5.3%	5.2%	5.8%	5.8%	5.5%	5.8%	5.6%	5.3%	4.8%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
8.1%	7.8%	7.8%	9.0%	8.2%	7.7%	8.1%	7.7%	7.6%	7.0%	*7.5%*	*8.0%*	Return on Shr. Equity	*9.0%*
8.1%	7.8%	7.8%	9.0%	8.2%	7.7%	8.1%	7.7%	7.6%	7.0%	*7.5%*	*8.0%*	Return on Com Equity E	*9.0%*
2.3%	2.2%	2.5%	3.6%	2.8%	2.4%	2.7%	2.3%	2.0%	1.5%	*2.5%*	*2.5%*	Retained to Com Eq	*3.5%*
71%	72%	67%	60%	66%	68%	66%	70%	74%	78%	*69%*	*68%*	All Div'ds to Net Prof	*63%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-1.5	-12.0	+11.5
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw) F	1573	1588	1557
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	NA	NA	NA
Fixed Charge Cov. (%)	277	230	219

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	--	-2.5%	*3.0%*
"Cash Flow"	5.5%	2.5%	*4.5%*
Earnings	4.0%	1.0%	*6.0%*
Dividends	3.5%	4.0%	*3.5%*
Book Value	5.0%	3.5%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2019	357.2	290.4	288.3	304.6	1240.5
2020	311.6	243.2	293.9	320.4	1169.1
2021	339.2	335.6	345.4	399.0	1419.2
2022	383.5	373.1	388.3	*405.1*	*1550*
2023	*400*	*390*	*400*	*410*	*1600*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2019	1.18	.64	.60	.92	3.33
2020	1.28	.39	.78	.90	3.35
2021	.99	.53	.53	1.18	3.23
2022	1.24	.67	.59	*1.25*	*3.75*
2023	*1.30*	*.65*	*.90*	*1.10*	*3.95*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.56	.56	.56	.56	2.24
2019	.5875	.5875	.5875	.5875	2.35
2020	.6175	.6175	.6175	.6175	2.47
2021	.63	.63	.63	.63	2.52
2022	.65	.65	.65	.65	

BUSINESS: ALLETE, Inc. is the parent of Minnesota Power, which supplies electricity to 146,000 customers in northeastern MN, & Superior Water, Light & Power in northwestern WI. Electric rev. breakdown: taconite mining/processing, 26%; paper/wood products, 9%; other industrial, 8%; residential, 13%; commercial, 13%; wholesale, 14%; other, 16%. ALLETE Clean Energy (ACE) owns renewable energy projects. Acq'd U.S. Water Services 2/15; sold it 3/19. Generating sources: coal, 28%; wind, 10%; other, 4%; purchased, 58%. Fuel costs: 40% of revs. '21 deprec. rate: 3.2%. Has 1,400 employees. Chairman, President & CEO: Bethany M. Owen. Inc.: Minnesota. Address: 30 West Superior St., Duluth, MN 55802-2093. Tel.: 218-279-5000. Internet: www.allete.com.

ALLETE's Minnesota Power subsidiary had its rate case hearing extended and the utility awaits a decision by the end of February, with final rates likely being implemented in mid-2023. Minnesota Power also filed a proposed agreement that would add 400 megawatts of wind energy and 300 megawatts of solar energy as the company remains committed to increasing renewable energy and providing 100% carbon-free energy by 2050. Meanwhile, Superior Water, Light and Power, the company's subsidiary in Wisconsin, expects a final order in its rate case by the end of the year. The case would generate $4.3 million of additional annual revenue if its proposed rate increase of 3.6% is approved.

ALLETE posted third-quarter earnings of $0.59 per share on net income of $33.7 million, a $6.1 million increase year over year. Interim rates at Minnesota Power, along with a strong showing from the regulated operations segment were the main drivers to an improved performance in the September period. Our earnings estimate remains at the midpoint of management's full-year updated earnings per share range of $3.60 to $3.90.

The Inflation Reduction Act should greatly improve the continued challenging operating environment. The biggest benefit should be the effect of production tax credits and investment tax credits. The tax credits will provide new investment options, especially in clean energy. The utility expects to add $45-$50 million of credits in 2023 due to the Act.

Shares of ALLETE have been downgraded to Below Average (4) for Timeliness. The stock is also trading above the midpoint of our 18-month Target Price Range due to a recent uptick in its value. In fact, these shares are up more than 8% since our last review in early September, among one of the best-performing equities in the utility industry, which has been under pressure due to rising interest rates. While long-term capital appreciation potential does not stand out, an attractive dividend yield of 3.9% is above the utility average. Too, ALLETE has a high score for Price Stability and is ranked Above Average (2) for Safety.

Zachary J. Hodgkinson *December 9, 2022*

(A) Diluted EPS. Excl. nonrec. gains (loss): '15, (46¢); '17, 25¢; '19, 26¢; loss on disc. ops.: '06, 2¢. '19 EPS don't sum due to rounding. Next earnings report due early Feb. (B) Div'ds historically paid in early Mar., June, Sept. and Dec. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. deferred charges. In '21: $9.62/sh. (D) In mill. (E) Rate base: Orig. cost depr. Rate all'd in MN on com. eq. in '18: 9.25%; earned on avg. com. eq., '21: 7.2%. Regul. Climate: Avg. (F) Summer peak in '21.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	35
Earnings Predictability	90

ALLIANT ENERGY NDQ-LNT

RECENT PRICE 55.78 | P/E RATIO 20.3 (Trailing: 21.0; Median: 20.0) | RELATIVE P/E RATIO 1.25 | DIV'D YLD 3.2% | VALUE LINE

TIMELINESS 4 Lowered 11/18/22

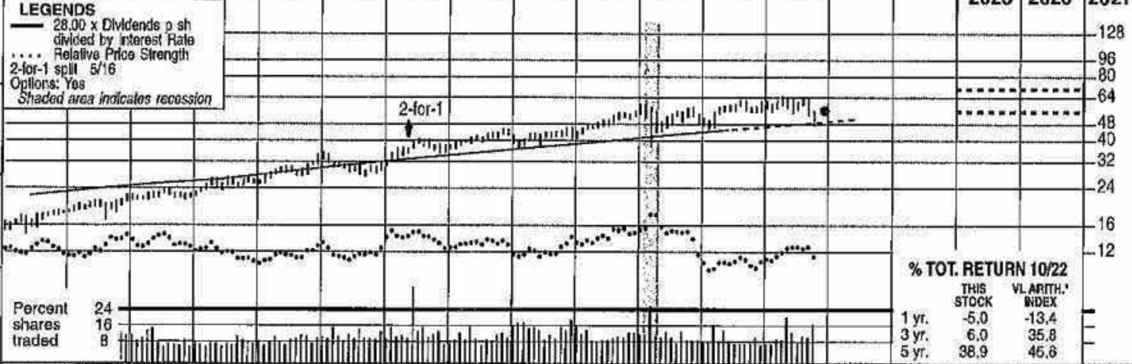
SAFETY 2 Raised 9/26/07

TECHNICAL 4 Lowered 12/9/22

BETA .85 (1.00 = Market)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	22.2	23.6	27.1	34.9	35.4	41.0	45.6	46.6	55.4	60.3	62.3	65.4	
Low:	17.0	20.9	21.9	25.0	27.1	30.4	36.6	36.8	40.8	37.7	46.0	47.2	

LEGENDS
— 28.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 5/16
Options: Yes
Shaded area indicates recession



Target Price Range 2025 | 2026 | 2027

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$45-$80	$63 (10%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+25%)	9%
Low	55	(Nil)	3%

Institutional Decisions

	4Q2022	2Q2022	3Q2022
to Buy	265	314	278
to Sell	259	232	263
Hld's(000)	195423	188290	192006

Percent shares traded 24 16 8

% TOT. RETURN 10/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-5.0	-13.4
3 yr.	6.0	35.8
5 yr.	38.9	45.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
14.46	15.57	16.67	15.51	15.40	16.51	13.94	14.77	15.10	14.34	14.58	14.62	14.97	14.89	13.67	14.65	*16.35*	*16.90*	Revenues per sh	*18.50*
2.16	2.56	2.28	2.10	2.60	2.75	2.95	3.34	3.49	3.45	3.43	3.97	4.32	4.59	4.92	5.25	*5.50*	*5.75*	"Cash Flow" per sh	*6.75*
1.03	1.35	1.27	.95	1.38	1.38	1.53	1.65	1.74	1.69	1.65	1.99	2.19	2.33	2.47	2.63	*2.70*	*2.95*	Earnings per sh A	*3.50*
.58	.64	.70	.75	.79	.85	.90	.94	1.02	1.10	1.18	1.26	1.34	1.42	1.52	1.61	*1.71*	*1.81*	Div'd Decl'd per sh B ■ †	*2.15*
1.71	2.46	3.98	5.43	3.91	3.03	5.22	3.32	3.78	4.25	5.26	6.34	6.92	6.69	5.47	4.67	*5.90*	*5.90*	Cap'l Spending per sh	*6.25*
11.42	12.15	12.78	12.54	13.05	13.57	14.12	14.79	15.54	16.41	16.96	18.09	19.43	21.24	22.76	23.91	*25.05*	*26.25*	Book Value per sh C	*30.25*
232.25	220.72	220.90	221.31	221.79	222.04	221.97	221.89	221.87	226.92	227.67	231.35	236.06	245.02	249.87	250.47	*251.00*	*251.50*	Common Shs Outst'g D	*253.00*
16.8	15.1	13.4	13.9	12.5	14.5	14.5	15.3	16.6	18.1	22.3	20.6	19.1	21.2	21.2	21.2	*Bold figures are*		Avg Ann'l P/E Ratio	*18.0*
.91	.80	.81	.93	.80	.91	.92	.86	.87	.91	1.17	1.04	1.03	1.13	1.09	1.13	*Value Line*		Relative P/E Ratio	*1.00*
3.3%	3.1%	4.1%	5.7%	4.6%	4.3%	4.1%	3.7%	3.5%	3.6%	3.2%	3.1%	3.2%	2.9%	2.9%	2.9%	*estimates*		Avg Ann'l Div'd Yield	*3.7%*

CAPITAL STRUCTURE as of 9/30/22
Total Debt $8611 mill. Due in 5 Yrs $2126 mill.
LT Debt $7570 mill. LT Interest $272 mill.
(LT interest earned: 3.3x)

Leases, Uncapitalized Annual rentals $2 mill.

Pension Assets-12/21 $1011 mill. Oblig $1251 mill.

Pfd Stock None

Common Stock 251,021,830 shs.

MARKET CAP: $14.0 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
3094.5	3276.8	3350.3	3253.6	3320.0	3382.2	3534.5	3647.7	3416.0	3669.0	*4100*	*4250*	Revenues ($mill)	*4700*
337.8	382.1	395.7	390.9	384.0	466.1	522.3	567.4	624.0	674.0	*700*	*745*	Net Profit ($mill)	*885*
21.5%	12.4%	10.1%	15.3%	13.4%	12.5%	8.4%	10.8%	10.8%	NMF	*4.0%*	*4.0%*	Income Tax Rate	*4.0%*
6.5%	8.1%	8.8%	9.4%	16.3%	10.7%	14.5%	16.3%	8.8%	3.7%	*4.0%*	*5.0%*	AFUDC % to Net Profit	*6.0%*
48.4%	46.1%	49.7%	47.3%	51.5%	47.8%	52.3%	50.6%	53.5%	52.9%	*54.5%*	*54.0%*	Long-Term Debt Ratio	*55.0%*
48.4%	50.8%	47.5%	50.0%	46.1%	49.8%	45.7%	47.6%	44.9%	47.1%	*45.5%*	*46.0%*	Common Equity Ratio	*45.0%*
6476.6	6461.0	7257.2	7446.3	8377.6	8392.8	10032	10938	12657	12725	*13875*	*14425*	Total Capital ($mill)	*17100*
7838.0	7147.3	6442.0	8970.2	9809.9	10798	12462	13527	14336	14987	*16025*	*17075*	Net Plant ($mill)	*20300*
6.3%	7.0%	6.5%	6.3%	5.6%	6.7%	6.3%	6.3%	5.9%	6.3%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.5%*
10.1%	11.0%	10.8%	10.0%	9.5%	10.6%	10.9%	10.5%	10.6%	11.3%	*11.0%*	*11.5%*	Return on Shr. Equity	*11.5%*
10.3%	11.3%	11.2%	10.2%	9.7%	10.9%	11.2%	10.7%	10.8%	11.0%	*11.0%*	*11.5%*	Return on Com Equity E	*11.5%*
3.9%	4.9%	4.6%	3.6%	2.8%	4.0%	4.4%	4.2%	4.2%	4.3%	*4.5%*	*4.5%*	Retained to Com Eq	*4.5%*
64%	57%	60%	66%	72%	64%	62%	61%	62%	62%	*61%*	*61%*	All Div'ds to Net Prof	*61%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-2.2	-2.3	+3.7
Avg. Indust. Use (MWH)	11448	11134	NA
Avg. Indust. Revs. per KWH (¢)	6.98	7.55	7.64
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	5626	5496	5486
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.6	+.6	+.8
Fixed Charge Cov. (%)	265	251	259

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-1.0%	-.5%	*4.5%*
"Cash Flow"	7.0%	7.5%	*5.5%*
Earnings	7.0%	8.0%	*6.0%*
Dividends	6.5%	6.5%	*6.0%*
Book Value	5.5%	7.0%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	987.2	790.2	990.2	880.1	3647.7
2020	916	763	920	817	3416.0
2021	901	817	1024	927	3669.0
2022	1068	943	1135	*954*	*4100*
2023	*1100*	*925*	*1175*	*1050*	*4250*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.53	.40	.94	.46	2.33
2020	.72	.54	.94	.26	2.47
2021	.68	.57	1.02	.35	2.63
2022	.77	.63	.90	*.40*	*2.70*
2023	*.80*	*.65*	*1.05*	*.45*	*2.95*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.335	.335	.335	.335	1.34
2019	.355	.355	.355	.355	1.42
2020	.38	.38	.38	.38	1.52
2021	.4025	.4025	.4025	.4025	1.61
2022	.4275	.4275	.4275	.4275	

BUSINESS: Alliant Energy Corporation (formerly Interstate Energy) is a holding company formed through the merger of WPL Holdings, IES Industries, and Interstate Power. Supplies electricity to 985,000 customers and gas to 425,000 customers in Wisconsin, Iowa, and Minnesota. Electric revenue by state: WI, 43%; IA, 56%. MN, 1%. Electric revenue: residential, 36%; commercial, 25%; industrial, 29%; wholesale, 8%; other, 2%. Generating sources: coal, 32%; gas, 32%; wind, 16%; other, 1%; purchased, 19%. Fuel costs: 25% of revs. '21 reported deprec. rates: 2.9%-6.1%. Has 3,300 employees. Chairman, President & CEO: John O. Larsen. Inc.: Wisconsin. Address: 4902 N. Biltmore Lane, Madison, Wisconsin 53718-2148. Tel.: 608-458-3311. Internet: www.alliantenergy.com.

Alliant Energy came up a bit short in the September quarter. Indeed, on a reported basis, the Wisconsin-based electric utility earned $0.90 a share in the period, down 12% year over year, even as overall revenue rose 11%, to nearly $1.14 billion. Weighing on EPS was, among other things, a one-time charge below the operating line (included in our estimates). Notably, Alliant wrote down the value of tax assets on its balance sheet after Iowa's Department of Revenue announced a reduction in state levies on corporate income beginning next year. That said, operating conditions remained generally favorable, with warmer-than-normal weather driving increased air-conditioner and electricity use across Alliant's three-state footprint.

The utility's investment roadmap includes a notable amount of energy storage. In late September, Alliant filed a plan with the Public Service Commission of Wisconsin, calling for the addition of 175 megawatts of battery storage in the state. Specifically, the facilities would be located in Grant and Wood counties, alongside two previously-approved solar arrays. Importantly, they'd provide bridge power for more than 180,000 homes at times when sun- and wind-power generation is inadequate.

The Inflation Reduction Act (IRA) that was signed into law in mid-August is expected to be a big benefit. As we understand it, new financing options under the IRA will enable Alliant Energy to take full ownership of 12 solar-power farms that it currently shares with several investment partners. According to a recent report, the transition could save the utility and its customers upwards of $138 million.

Shares of Alliant Energy are ranked 4 (Below Average) for relative year-ahead price performance. At the recent quotation, we think that buy-and-hold investors will also do better elsewhere. Notably, at 3.2%, the dividend yield is below both the utility average and less-risky returns offered by United States Treasuries. Prospects over the next 18 months and the 3- to 5-year period are also subpar. Like many electric utility issues, the recent quotation is within our 2025-2027 Target Price Range.

Nils C. Van Liew *December 9, 2022*

(A) Diluted EPS. Excl. nonrecurring losses: '11, 1¢; '12, 8¢. '20 & '21 EPS don't sum due to rounding. Next earnings report due late Feb. (B) Dividends historically paid in mid-Feb., May, Aug., and Nov. ■ Dividend reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '21: $1,980 mill., $7.91/sh. (D) In millions, adj. for split. (E) Rate base: Orig. cost. Rates all'd on com. eq. in IA in '20: various; in WI in '22: 10%; earned on avg. com. eq., '21: 11.3%. Regulatory Climate: Wisconsin, Above Average; Iowa, Average.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	70
Earnings Predictability	95

AMEREN NYSE-AEE

RECENT PRICE 87.94 | P/E RATIO 20.8 (Trailing: 22.0; Median: 19.0) | RELATIVE P/E RATIO 1.28 | DIV'D YLD 2.8% | VALUE LINE

TIMELINESS 4 Lowered 12/2/22
SAFETY 1 Raised 9/10/21
TECHNICAL 4 Lowered 12/9/22
BETA .85 (1.00 = Market)

18-Month Target Price Range
Low-High: $81-$129 | Midpoint (% to Mid): $105 (20%)

2025-27 PROJECTIONS

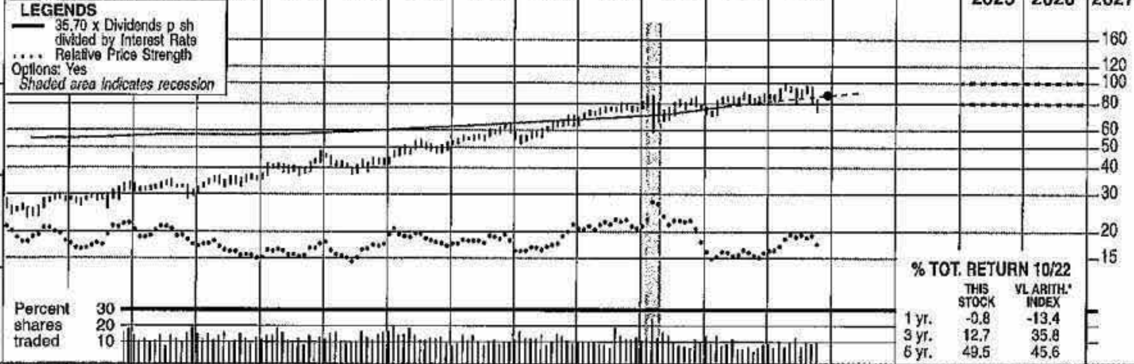
	Price	Gain	Ann'l Total Return
High	100	(+15%)	6%
Low	80	(-10%)	1%

Institutional Decisions

	1Q2022	2Q2022	3Q2022
to Buy	294	305	287
to Sell	262	257	274
Hld's(000)	200507	201631	204282

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	34.1	35.3	37.3	48.1	46.8	54.1	64.9	70.9	80.9	87.7	90.8	99.2
Low:	25.5	28.4	30.6	35.2	37.3	41.5	51.4	51.9	63.1	58.7	69.8	73.3

Target Price Range 2025 | 2026 | 2027



% TOT. RETURN 10/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-0.8	-13.4
3 yr.	12.7	35.8
5 yr.	49.5	45.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
33.30	36.23	36.92	29.87	31.77	31.04	28.14	24.06	24.95	25.13	25.04	25.46	25.73	24.00	22.87	24.81	*27.25*	*28.10*	Revenues per sh	*30.00*
6.02	6.76	6.44	6.06	6.33	5.87	5.87	5.25	5.77	6.08	6.59	6.80	7.64	7.83	8.08	8.89	*9.50*	*10.05*	"Cash Flow" per sh	*11.75*
2.66	2.98	2.88	2.78	2.77	2.47	2.41	2.10	2.40	2.38	2.68	2.77	3.32	3.35	3.50	3.84	*4.10*	*4.35*	Earnings per sh A	*5.25*
2.54	2.54	2.54	1.54	1.54	1.56	1.60	1.60	1.61	1.66	1.72	1.78	1.85	1.92	2.00	2.20	*2.36*	*2.52*	Div'd Decl'd per sh B ■	*3.10*
4.99	6.96	9.75	7.51	4.66	4.50	5.49	5.87	7.66	8.12	8.78	9.05	9.56	9.92	13.02	13.67	*12.90*	*12.55*	Cap'l Spending per sh	*13.00*
31.86	32.41	32.80	33.08	32.15	32.64	27.27	26.97	27.67	28.63	29.27	29.61	31.21	32.73	35.29	37.64	*40.20*	*42.90*	Book Value per sh C	*51.25*
206.60	208.30	212.30	237.40	240.40	242.60	242.63	242.63	242.63	242.63	242.63	242.63	244.50	246.20	253.30	257.70	*262.50*	*267.00*	Common Shs Outst'g D	*280.00*
19.4	17.4	14.2	9.3	9.7	11.9	13.4	16.5	16.7	17.5	18.3	20.6	18.3	22.1	22.2	21.4	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*17.5*
1.05	.92	.85	.62	.62	.75	.85	.93	.88	.88	.96	1.04	.99	1.18	1.14	1.14			Relative P/E Ratio	*.95*
4.9%	4.9%	6.2%	6.0%	5.8%	5.3%	5.0%	4.6%	4.0%	4.0%	3.5%	3.1%	3.0%	2.6%	2.6%	2.7%			Avg Ann'l Div'd Yield	*3.4%*

CAPITAL STRUCTURE as of 9/30/22
Total Debt $14798 mill. Due in 5 Yrs $3446 mill.
LT Debt $13577 mill. LT Interest $436 mill.
(LT interest earned: 3.8x)
Pension Assets-12/21 $5745 mill. Oblig $5457 mill.
Pfd Stock $129 mill. Pfd Div'd $5 mill.
807,595 sh. $3.50 to $5.50 cum. (no par), $100 stated val., redeem. $102.176-$110/sh.; 487,508 sh. 4.00% to 5.16%, $100 par, redeem. $100-$104.30/sh.
Common Stock 258,522,169 shs. as of 10/31/22
MARKET CAP: $23 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
6828.0	5838.0	6053.0	6098.0	6076.0	6177.0	6291.0	5910.0	5794.0	6394.0	*7150*	*7500*	Revenues ($mill)	*8400*
589.0	518.0	593.0	585.0	659.0	683.0	821.0	834.0	877.0	995.0	*1075*	*1165*	Net Profit ($mill)	*1455*
36.9%	37.5%	38.9%	38.3%	36.7%	38.2%	22.4%	17.9%	15.0%	13.6%	*12.0%*	*12.0%*	Income Tax Rate	*12.0%*
6.1%	7.1%	5.7%	5.1%	4.1%	5.6%	6.9%	5.8%	5.5%	6.0%	*6.0%*	*5.0%*	AFUDC % to Net Profit	*4.0%*
49.5%	45.2%	47.2%	49.3%	47.7%	49.2%	50.3%	52.1%	55.0%	56.1%	*55.5%*	*53.5%*	Long-Term Debt Ratio	*51.0%*
49.4%	53.7%	51.7%	49.7%	51.3%	49.8%	48.8%	47.1%	44.3%	43.3%	*44.0%*	*46.0%*	Common Equity Ratio	*48.5%*
13384	12190	12975	13968	13840	14420	15632	17116	20158	22391	*23900*	*24950*	Total Capital ($mill)	*29500*
16096	16205	17424	18799	20113	21466	22810	24376	26807	29261	*31225*	*33050*	Net Plant ($mill)	*38400*
6.0%	5.6%	5.8%	5.3%	6.0%	6.0%	6.4%	6.0%	5.3%	5.3%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
8.7%	7.7%	8.7%	8.3%	9.1%	9.3%	10.6%	10.2%	9.7%	10.1%	*10.0%*	*10.0%*	Return on Shr. Equity	*10.0%*
8.8%	7.8%	8.7%	8.3%	9.2%	9.4%	10.7%	10.3%	9.7%	10.2%	*10.0%*	*10.0%*	Return on Com Equity E	*10.0%*
3.0%	1.9%	2.9%	2.5%	3.3%	3.4%	4.8%	4.4%	4.2%	4.4%	*4.5%*	*4.5%*	Retained to Com Eq	*4.0%*
66%	76%	67%	70%	64%	64%	56%	57%	57%	57%	*58%*	*58%*	All Div'ds to Net Prof	*60%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-3.5	-5.6	+2.1
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	307	291	325

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-2.5%	-1.0%	*4.0%*
"Cash Flow"	3.0%	6.0%	*6.0%*
Earnings	3.0%	7.5%	*6.5%*
Dividends	3.0%	4.0%	*7.0%*
Book Value	1.0%	4.5%	*6.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1556	1379	1659	1316	5910
2020	1440	1398	1628	1328	5794
2021	1566	1472	1811	1545	6394
2022	1879	1726	2306	*1239*	*7150*
2023	*1900*	*1700*	*2100*	*1800*	*7500*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.78	.72	1.47	.38	3.35
2020	.59	.98	1.47	.46	3.50
2021	.91	.80	1.65	.48	3.84
2022	.97	.80	1.74	*.59*	*4.10*
2023	*1.00*	*.90*	*1.80*	*.65*	*4.35*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.4575	.4575	.4575	.475	1.85
2019	.475	.475	.475	.495	1.92
2020	.495	.495	.495	.515	2.00
2021	.55	.55	.55	.55	2.20
2022	.59	.59	.59	.59	

BUSINESS: Ameren Corporation is a holding company formed through the merger of Union Electric and CIPSCO. Has 1.2 million electric and 127,000 gas customers in Missouri; 1.2 million electric and 813,000 gas customers in Illinois. Discontinued nonregulated power-generation operation in '13. Electric revenue breakdown: residential, 49%; commercial, 34%; industrial, 8%; other, 9%. Generating sources: coal, 73%; nuclear, 11%; hydro & other, 9%; purchased, 7%. Fuel costs: 25% of revenues. '21 reported deprec. rates: 3%-4%. Has 9,100 employees. Chairman: Warner L. Baxter. President & CEO: Martin J. Lyons, Jr. Inc.: Missouri. Address: One Ameren Plaza, 1901 Chouteau Ave., P.O. Box 66149, St. Louis, MO 63166-6149. Tel.: 314-621-3222. Internet: www.ameren.com.

Ameren reported in-line results for the September quarter. Earnings per share of $1.74 were a penny higher than our estimate and 5% greater than the year-ago tally. Earnings at Ameren Missouri, the largest segment, benefited from higher electric service rates. This was partially offset by higher operations and maintenance expenses derived from unfavorable market returns and company-owned life insurance investments. Earnings at the three remaining business segments were solid, primarily due to increased investments in infrastructure.

The company's guidance has improved a bit. Due to strong execution, management narrowed the 2022 earnings guidance to a range of $4.00 to $4.15 per share. This compares to the initial guidance range of $3.95 to $4.15 per share. Importantly, the year-to-date benefits it has seen from weather and higher-than-expected 30-year Treasury rates are mostly being offset by the aforementioned company-owned life insurance investment performance, as well as higher than expected short-term and long-term borrowing rates. The current five-year plan includes a 6% to 8% compounded annual growth rate for earnings from 2022 through 2026. This should be driven primarily by strong rate base growth and infrastructure investment. It expects dividend growth to be in line with long-term earnings growth and is planning for a payout ratio range of 55% to 70%.

Business investment is paying off. At Ameren Missouri, the company estimates that over 6.5 million minutes of customer outages have been avoided in 2022 due to recent infrastructure investments. Meanwhile, the Inflation Reduction Act (IRA) was enacted in August, and is designed to help reduce the cost of the clean energy transition. It provides tax credits for wind, solar, and nuclear energy centers, as well as energy storage, carbon capture utilization and hydrogen development. The incentives in the IRA align well with the companywide goal of reaching net zero carbon emissions by 2045.

The dividend yield of this high-quality stock is below the utility mean. The recent price is within our 2025-2027 Target Price Range.

Kevin Downing — *December 9, 2022*

(A) Diluted EPS. Excl. nonrec. gain (losses): '10, ($2.19); '11, (32¢); '12, ($6.42); '17, (63¢); gain (loss) from discontinued ops.: '13, (92¢); '15, 21¢. Next earnings report due mid-Feb.
(B) Div'ds paid late Mar., June, Sept., & Dec. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '21: $6.60/sh. (D) In mill. (E) Rate base: Orig. cost depr. Rate allowed on com. eq. in MO in '22: elec. & gas, none specified; in IL: electric, varies; in '21: gas, 9.67%; earned on avg. com. eq., '21: 10.6%. Regulatory Climate: MO, Average; IL, Below Average.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	85
Earnings Predictability	95

AMERICAN ELEC. PWR. NDQ-AEP

RECENT PRICE	95.22	P/E RATIO	18.6 (Trailing: 19.7; Median: 17.0)	RELATIVE P/E RATIO	1.14	DIV'D YLD	3.5%	VALUE LINE

TIMELINESS 3 Raised 4/1/22

SAFETY 1 Raised 3/17/17

TECHNICAL 2 Lowered 11/18/22

BETA .75 (1.00 = Market)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	41.7	45.4	51.6	63.2	65.4	71.3	78.1	81.1	96.2	105.0	91.5	105.6
Low:	33.1	37.0	41.8	45.8	52.3	56.8	61.8	62.7	72.3	65.1	74.8	80.3

Target Price Range 2025 | 2026 | 2027

18-Month Target Price Range

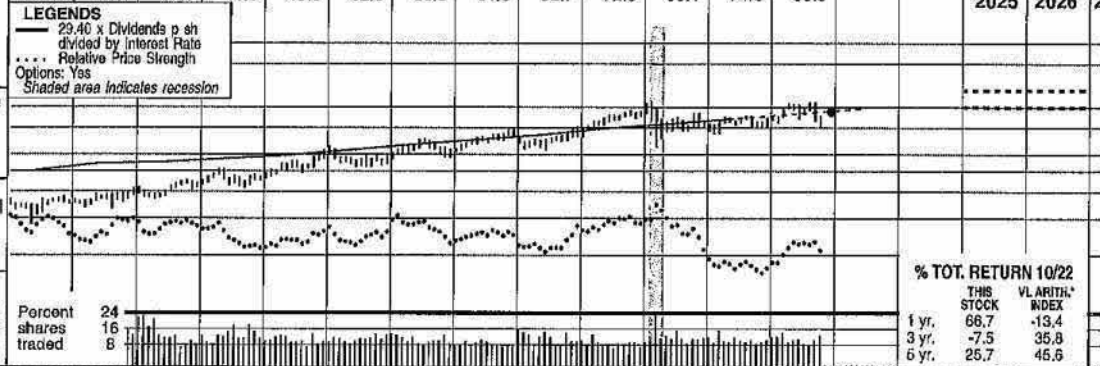
Low-High	Midpoint (% to Mid)
\$89-\$127	\$108 (15%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	120	(+25%)	9%
Low	100	(+5%)	5%

Institutional Decisions

	1Q2022	2Q2022	3Q2022
to Buy	673	634	624
to Sell	475	521	499
Hld's(000)	382433	385400	384675



% TOT. RETURN 10/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	66.7	-13.4
3 yr.	-7.5	35.8
5 yr.	25.7	45.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
31.82	33.41	35.56	28.22	30.01	31.27	30.77	31.48	34.78	33.51	33.31	31.35	32.84	31.49	30.04	33.30	*35.20*	*35.95*	Revenues per sh	*38.55*
6.67	6.80	6.84	6.32	6.29	6.83	6.92	7.02	7.57	7.98	8.47	7.95	8.77	9.36	10.28	10.98	*11.50*	*11.95*	"Cash Flow" per sh	*14.00*
2.86	2.86	2.99	2.97	2.60	3.13	2.98	3.18	3.34	3.59	4.23	3.62	3.90	4.08	4.42	4.96	*5.00*	*5.35*	Earnings per sh A	*6.50*
1.50	1.58	1.64	1.64	1.71	1.85	1.88	1.95	2.03	2.15	2.27	2.39	2.53	2.71	2.84	3.00	*3.17*	*3.35*	Div'd Decl'd per sh B ■ †	*4.00*
8.89	8.88	9.83	6.19	5.07	5.74	6.45	7.75	8.68	9.37	9.98	11.79	12.89	12.43	12.72	11.43	*15.35*	*14.15*	Cap'l Spending per sh	*14.00*
23.73	25.17	26.33	27.49	28.33	30.33	31.37	32.98	34.37	36.44	35.38	37.17	38.58	39.73	41.38	44.49	*47.30*	*50.30*	Book Value per sh C	*59.00*
396.67	400.43	406.07	478.05	480.81	483.42	485.67	487.78	489.40	491.05	491.71	492.01	493.25	494.17	496.60	504.21	*514.00*	*523.00*	Common Shs Outst'g D	*545.00*
12.9	16.3	13.1	10.0	13.4	11.9	13.8	14.5	15.9	15.8	15.2	19.3	18.0	21.4	19.6	17.1	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*17.0*
.70	.87	.79	.67	.85	.75	.88	.81	.84	.80	.80	.97	.97	1.14	1.01	.93			Relative P/E Ratio	*.95*
4.1%	3.4%	4.2%	5.5%	4.9%	5.0%	4.6%	4.2%	3.8%	3.8%	3.5%	3.4%	3.6%	3.1%	3.3%	3.5%			Avg Ann'l Div'd Yield	*3.6%*

CAPITAL STRUCTURE as of 9/30/22
Total Debt \$36349 mill. Due in 5 Yrs \$12886 mill.
LT Debt \$33647 mill. LT Interest \$1067 mill.
Incl. \$549.4 mill. securitized bonds. Incl. \$500.7 mill. finance leases.
(LT interest earned: 3.2x)
Leases, Uncapitalized Annual rentals \$119.6 mill.
Pension Assets-12/21 \$5352.9 mill. Oblig \$5187.0 mill.

Pfd Stock None

Common Stock 513,863,678 shs. as of 10/27/22

MARKET CAP: \$48.9 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
14945	15357	17020	16453	16380	15425	16196	15561	14919	16792	*18100*	*18800*	Revenues (\$mill)	*21000*
1443.0	1549.0	1634.0	1763.4	2073.6	1783.2	1923.8	2019.0	2200.1	2488.1	*2580*	*2775*	Net Profit (\$mill)	*3565*
33.9%	36.2%	37.8%	35.1%	26.8%	33.7%	5.8%	.7%	1.9%	4.6%	*7.0%*	*7.0%*	Income Tax Rate	*7.0%*
11.2%	7.3%	9.0%	11.0%	8.0%	9.0%	10.7%	12.7%	9.7%	7.8%	*7.0%*	*7.0%*	AFUDC % to Net Profit	*5.0%*
50.6%	51.1%	49.0%	49.8%	50.0%	51.5%	53.2%	56.1%	58.5%	58.3%	*58.0%*	*58.0%*	Long-Term Debt Ratio	*57.5%*
49.4%	48.9%	51.0%	50.2%	50.0%	48.5%	46.8%	43.9%	41.5%	41.7%	*42.0%*	*42.0%*	Common Equity Ratio	*42.5%*
30823	32913	33001	35633	34775	37707	40677	44759	49537	53734	*57775*	*62950*	Total Capital (\$mill)	*75900*
38763	40997	44117	46133	45639	50262	55099	60138	63902	66001	*70650*	*74600*	Net Plant (\$mill)	*87300*
6.1%	6.0%	6.3%	6.1%	7.2%	5.9%	5.9%	5.6%	5.6%	5.6%	*4.5%*	*4.5%*	Return on Total Cap'l	*5.5%*
9.5%	9.6%	9.7%	9.9%	11.9%	9.8%	10.1%	10.3%	10.7%	11.1%	*11.0%*	*10.5%*	Return on Shr. Equity	*11.0%*
9.5%	9.6%	9.7%	9.9%	11.9%	9.8%	10.1%	10.3%	10.7%	11.1%	*11.0%*	*10.5%*	Return on Com Equity E	*11.0%*
3.5%	3.7%	3.8%	3.9%	5.5%	3.2%	3.5%	3.4%	3.8%	4.3%	*4.0%*	*4.0%*	Retained to Com Eq	*4.5%*
63%	62%	61%	60%	54%	67%	65%	67%	65%	61%	*63%*	*63%*	All Div'ds to Net Prof	*62%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-2.2	- -	+3.0
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.3	+1.0	NA
Fixed Charge Cov. (%)	234	243	272

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	.5%	-1.5%	*3.5%*
"Cash Flow"	4.5%	5.0%	*5.5%*
Earnings	4.5%	4.0%	*6.5%*
Dividends	5.0%	6.0%	*6.0%*
Book Value	4.0%	3.5%	*6.0%*

Cal-endar	QUARTERLY REVENUES (\$ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	4056	3573	4315	3616	15561
2020	3747	3494	4066	3610	14918
2021	4281	3826	4623	4061	16792
2022	4593	4640	5526	*3341*	*18100*
2023	*4800*	*4300*	*5150*	*4550*	*18800*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.16	.93	1.48	.51	4.08
2020	1.00	1.05	1.50	.87	4.42
2021	1.15	1.15	1.59	1.07	4.96
2022	1.41	1.02	1.33	*1.24*	*5.00*
2023	*1.30*	*1.25*	*1.75*	*1.05*	*5.35*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.62	.62	.62	.67	2.53
2019	.67	.67	.67	.70	2.71
2020	.70	.70	.70	.74	2.84
2021	.74	.74	.74	.78	3.00
2022	.78	.78	.78	.83	

BUSINESS: American Electric Power Company Inc. (AEP), through 10 operating utilities, serves 5.5 million customers in Arkansas, Kentucky, Indiana, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia, & West Virginia. Has a transmission subsidiary. Electric revenue breakdown: residential, 43%; commercial, 23%; industrial, 18%; wholesale, 10%; other, 6%. Sold commercial barge operation in '15. Generating sources not available. Fuel costs: 33% of revenues. '21 reported depreciation rates (utility): 2.6%-12.5%. Has 16,700 employees. Chairman, President & CEO: Nicholas K. Akins. COO: Lisa Barton. Incorporated: New York. Address: 1 Riverside Plaza, Columbus, Ohio 43215-2373. Telephone: 614-716-1000. Internet: www.aep.com.

American Electric Power will soon complete a divestiture, and the company is interested in shedding other assets. AEP expects to raise \$1.45 billion from the sale of its Kentucky Power subsidiary. The motivation for the sale is the entity's lack of an adequate return on equity. The last remaining hurdle before the deal can go through is the approval of an application, which should be received by mid December. The transaction would then close by early January. The company has also started accepting initial bids for its 1,600-megawatt portfolio of nonregulated renewable-energy projects, either piecemeal or as a whole. Management is now moving on to the due diligence process with select bidders. It expects the process to close in the June quarter of 2023. Meanwhile, the company is conducting a strategic review of the retail business which it expects to complete in the first half of 2023. Following divestitures, AEP plans to expand its investments in regulated renewable-energy projects, which have less risk than nonutility assets, and electric transmission.

The company appears well positioned to meet or exceed its full-year guidance. American continues to realize above-forecast, weather-normalized load (the amount of electricity on the grid at any given time), which is now 2.6% above pre-pandemic levels. Year to date, residential, commercial, and industrial sales comparisons are up .3%, 3.8%, and 5.5%, respectively. This compares to the company's 2.9% (revised upward from 1.6%) retail sales forecast for 2022. The company should continue to benefit from rate relief, increased investment in its transmission business, and volume growth. Our \$5.00 GAAP earnings estimate is within management's guidance (on a GAAP basis) of \$4.97-\$5.07 a share. At the analyst day in early October, the company established its 2023 earnings per share guidance range at \$5.19-\$5.39 and the long-term bottom line growth rate at 6%-7%.

The dividend yield of this top-quality stock is at the utility average. Total return potential is unspectacular for the next 18 months and Timeliness is average. Further, the recent quotation is just below our 2025-2027 Target Price Range.

Kevin Downing *December 9, 2022*

(A) Diluted EPS. Excl. nonrec. gains (losses): '06, (20¢); '07, (20¢); '08, 40¢; '10, (7¢); '11, 89¢; '12, (38¢); '13, (14¢); '16, (\$2.99); '17, 26¢; '19, (20¢); gains (loss) from disc. ops.: '06, 2¢; '08, 3¢; '15, 58¢; '16, (1¢). Next earnings report due late Jan. (B) Div'ds paid early Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. † Shareholder invest. plan avail. (C) Incl. intang. In '21: \$17.04/sh. (D) In mill. (E) Rate base: various. Rates allowed on com. eq.: 9.3%-10.9%; earned on avg. com. eq., '21: 11.6%. Regulatory Climate: Average.

Company's Financial Strength	A+
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	95

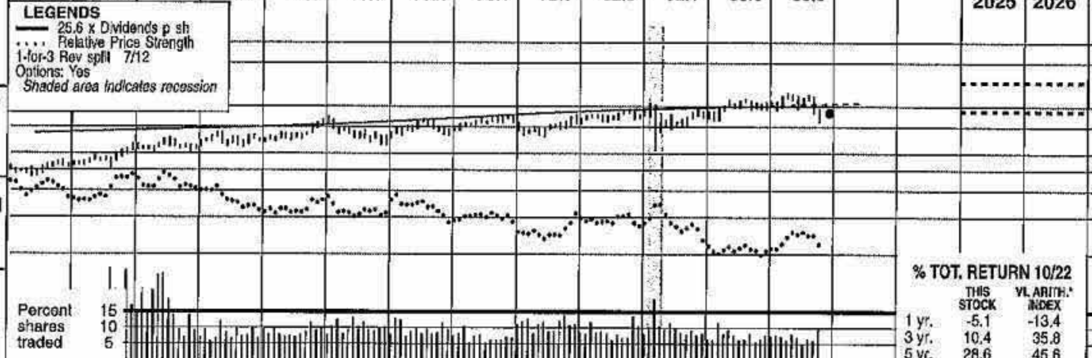
DUKE ENERGY NYSE-DUK

RECENT PRICE	93.18	P/E RATIO	17.1 (Trailing: 17.7; Median: 18.0)	RELATIVE P/E RATIO	1.11	DIV'D YLD	4.3%	VALUE LINE

TIMELINESS 3 Raised 5/20/22
SAFETY 2 New 6/1/07
TECHNICAL 2 Lowered 11/4/22
BETA .85 (1.00 = Market)

High:	66.4	71.1	75.5	87.3	90.0	87.8	91.8	91.4	97.4	103.8	108.4	116.3
Low:	50.6	59.6	64.2	67.1	65.5	70.2	76.1	72.0	82.5	62.1	85.6	83.8

Target Price Range 2025 | 2026 | 2027



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$88-$134	$111 (20%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	130	(+40%)	12%
Low	95	(Nil)	5%

Institutional Decisions

	4Q2021	1Q2022	2Q2022
to Buy	934	942	877
to Sell	627	651	688
Hld's(000)	484677	487269	491735

% TOT. RETURN 10/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-5.1	-13.4
3 yr.	10.4	35.8
5 yr.	28.6	45.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
26.32	30.24	31.15	29.18	32.22	32.63	27.88	34.84	33.84	34.10	32.49	33.66	33.73	34.21	31.04	32.64	*35.05*	*36.05*	Revenues per sh	*37.90*
7.86	8.11	7.34	7.58	8.49	8.68	6.80	8.56	9.11	9.40	9.20	10.01	11.05	12.12	12.04	12.60	*13.25*	*14.00*	"Cash Flow" per sh	*16.00*
2.76	3.60	3.03	3.39	4.02	4.14	3.71	3.98	4.13	4.10	3.71	4.22	4.72	5.06	5.12	5.24	*5.45*	*5.75*	Earnings per sh A	*6.50*
--	2.58	2.70	2.82	2.91	2.97	3.03	3.09	3.15	3.24	3.36	3.49	3.64	3.75	3.82	3.90	*3.98*	*4.06*	Div'd Decl'd per sh B ■	*4.30*
8.07	7.43	10.35	9.85	10.84	9.80	7.81	7.83	7.62	9.83	11.29	11.50	12.91	15.17	12.88	12.63	*16.00*	*16.75*	Cap'l Spending per sh	*16.75*
62.30	50.40	49.51	49.85	50.84	51.14	58.04	58.54	57.81	57.74	58.62	59.63	60.27	61.20	59.82	61.55	*62.75*	*64.50*	Book Value per sh C	*70.00*
418.96	420.62	423.96	436.29	442.96	445.29	704.00	706.00	707.00	688.00	700.00	700.00	727.00	733.00	769.00	769.00	*770.00*	*770.00*	Common Shs Outst'g D	*770.00*
--	16.1	17.3	13.3	12.7	13.8	17.5	17.4	17.9	18.2	21.3	19.9	17.0	17.7	17.1	18.9	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*17.0*
--	.85	1.04	.89	.81	.87	1.11	.98	.94	.92	1.12	1.00	.92	.94	.88	1.02	*estimates*		Relative P/E Ratio	*.95*
--	4.4%	5.2%	6.2%	5.7%	5.2%	4.7%	4.4%	4.3%	4.3%	4.3%	4.2%	4.5%	4.2%	4.4%	3.9%			Avg Ann'l Div'd Yield	*3.9%*

CAPITAL STRUCTURE as of 6/30/22
Total Debt $70193 mill. **Due in 5 Yrs** $19536 mill.
LT Debt $63147 mill. **LT Interest** $2206 mill.
Incl. $915 mill. finance leases.
(LT interest earned: 2.7x)
Leases, Uncapitalized Annual rentals $225 mill.
Pension Assets-12/21 $9235 mill.
Oblig $8207 mill.
Pfd Stock $1962 mill. **Pfd Div'd** $107 mill.
40 mill. shs. 5.75%, cum., $25 liq. value, redeemable at $25.50 prior to 6/15/24; 1 mill. shs. 4.875%, cum., $1000 liq. value.
Common Stock 769,968,724 shs. as of 7/31/22
MARKET CAP: $84.6 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
19624	24598	23925	23459	22743	23565	24521	25079	23868	25097	*27000*	*27750*	Revenues ($mill)	*29200*
2136.0	2813.0	2934.0	2854.0	2560.0	2963.0	3339.0	3747.0	3878.0	4133.0	*4200*	*4500*	Net Profit ($mill)	*5040*
30.2%	32.6%	30.6%	32.2%	31.0%	30.4%	14.1%	12.7%	.3%	5.1%	*10.0%*	*9.0%*	Income Tax Rate	*9.0%*
22.3%	8.8%	7.2%	9.2%	11.7%	12.3%	11.4%	8.0%	6.9%	5.9%	*8.0%*	*7.0%*	AFUDC % to Net Profit	*7.0%*
47.0%	48.0%	47.7%	48.6%	52.6%	54.0%	53.8%	54.0%	53.7%	55.1%	*56.5%*	*58.5%*	Long-Term Debt Ratio	*61.0%*
52.9%	52.0%	52.3%	51.4%	47.4%	46.0%	46.2%	44.1%	44.4%	43.1%	*42.0%*	*40.0%*	Common Equity Ratio	*37.5%*
77307	79482	78088	77222	86609	90774	94940	101807	103589	109744	*115150*	*124525*	Total Capital ($mill)	*144100*
68558	69490	70046	75709	82520	86391	91694	102127	106782	111408	*117725*	*124375*	Net Plant ($mill)	*141100*
3.6%	4.6%	4.8%	4.8%	4.0%	4.3%	4.6%	4.7%	4.8%	4.8%	*4.5%*	*4.5%*	Return on Total Cap'l	*4.5%*
5.2%	6.8%	7.2%	7.2%	6.2%	7.1%	7.6%	8.0%	8.1%	8.4%	*8.5%*	*9.0%*	Return on Shr. Equity	*9.0%*
5.2%	6.8%	7.2%	7.2%	6.2%	7.1%	7.6%	8.3%	8.2%	8.5%	*8.5%*	*9.0%*	Return on Com Equity E	*9.0%*
.9%	1.5%	1.7%	1.5%	.6%	1.2%	2.0%	2.4%	2.3%	1.9%	*2.5%*	*2.5%*	Retained to Com Eq	*3.0%*
82%	78%	76%	79%	91%	83%	74%	71%	73%	78%	*76%*	*73%*	All Div'ds to Net Prof	*68%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-.9	-2.3	+2.0
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	NA	NA	NA
Fixed Charge Cov. (%)	233	183	209

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	.5%	-.5%	*2.5%*
"Cash Flow"	4.0%	5.0%	*5.0%*
Earnings	3.0%	4.5%	*5.0%*
Dividends	3.0%	3.5%	*2.0%*
Book Value	2.0%	1.0%	*2.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	6163	5873	6940	6103	25079
2020	5949	5421	6721	5777	23868
2021	6150	5758	6951	6238	25097
2022	7132	6685	*7255*	*5928*	*27000*
2023	*7250*	*6750*	*7375*	*6375*	*27750*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.24	1.12	1.79	.91	5.06
2020	1.14	1.08	1.87	1.03	5.12
2021	1.26	1.15	1.88	.94	5.24
2022	1.30	1.14	*1.86*	*1.15*	*5.45*
2023	*1.30*	*1.20*	*2.00*	*1.10*	*5.75*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.89	.89	.9275	.9275	3.64
2019	.9275	.9275	.945	.945	3.75
2020	.945	.945	.965	.965	3.82
2021	.965	.965	.985	.985	3.90
2022	.985	.985	1.005		

BUSINESS: Duke Energy Corporation is a holding company for utilities with 7.6 mill. elec. customers in NC, FL, IN, SC, OH, & KY, and 1.6 mill. gas customers in OH, KY, NC, SC, and TN. Owns independent power plants & has 25% stake in National Methanol in Saudi Arabia. Acq'd Progress Energy 7/12; Piedmont Natural Gas 10/16; discontinued most int'l ops. in '16. Elec. rev. breakdown: residential, 45%; commercial, 28%; industrial, 13%; other, 14%. Generating sources: gas, 32%; nuclear, 30%; coal, 18%; other, 1%; purchased, 19%. Fuel costs: 28% of revs. '21 reported deprec. rate: 2.9%. Has 27,600 employees. Chairman, President & CEO: Lynn J. Good. Inc.: DE. Address: 550 South Tryon St., Charlotte, NC 28202-1803. Tel.: 704-382-3853. Internet: www.duke-energy.com.

Duke Energy has a number of rate cases pending. In North Carolina, Duke Energy Progress requested a boost of $326 million (8.5%) in 2023, $151 million (3.9%) in 2024, and $138 million (3.6%) in 2025. In South Carolina, Duke Energy Progress proposed its first base rate case in four years, and expects rates to go into effect in early 2023. In Ohio, the utility is seeking a $55 million (3%) hike, as the rate case hearing nears a conclusion. Adjusted second-quarter earnings of $1.14 a share, slightly outperformed our call of $1.10. Our 2022 full-year estimate remains at $5.45 a share. Management reaffirmed a range of $5.30 to $5.60, and a long-term earnings growth rate of 5% to 7% through 2026. Rate relief and strong retail volumes were the main drivers to the bottom line in the second period. Volume growth increased 2.6% year over year, which is higher than 2019 levels.

We look for a strong earnings performance in 2023, near the company's growth target of between 5% and 7%. Higher electric volumes should continue, and Duke Energy raised its load growth prediction to 1.5%-2% from 1.5%. The utility is estimating cost mitigation of $200 million starting in 2023, due to rising interest rates and inflation.

The company is very focused on carbon reduction and the development of clean and renewable energy projects. Currently, the utility has 5,000 megawatts of Commericial wind, solar, and battery projects, ranking it within the top-10 largest renewable companies in the United States. By 2035, the company intends to reach 30,000 megawatts of renewable energy. Duke plans to invest $145 billion over the next 10 years and achieve net-zero carbon emissions by 2050 in its clean energy transition. Management expects carbon emission reduction to exceed 50% by 2030, and 80% by 2040.

The stock has dropped 20% in value since our August report, alongside losses by most of its peers over that time due to rising interest rates. Despite the stock's price reduction, its 18-month and 3- to 5-year capital appreciation potential does not stand out. Meanwhile, this issue is ranked 3 (Average) for Timeliness.

Zachary J. Hodgkinson November 11, 2022

(A) Dil. EPS. Excl. net nonrec. losses: '12, 64¢; '13, 22¢; '14, 59¢; '15, 5¢; '16, 60¢; '18, 96; '20, $3.40; '21, 30¢; 1Q22, 22¢; net nonrec gain: '17, 14¢. 2021 EPS don't sum to annual due to rounding. Next egs. due early Feb. (B) Div'ds paid mid-Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. intang. In '21: $41.34/sh. (D) In mill., adj. for rev. split. (E) Rate base: Net orig. cost. Rate all'd on com. eq. in '21 in NC: 9.6%; in '19 in SC: 9.5%; in '20 in FL: 9.5%-11.5%; in '20 in IN: 9.7%. Reg. Clim.: NC, SC Avg.; OH, IN Above Avg.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	45
Earnings Predictability	100

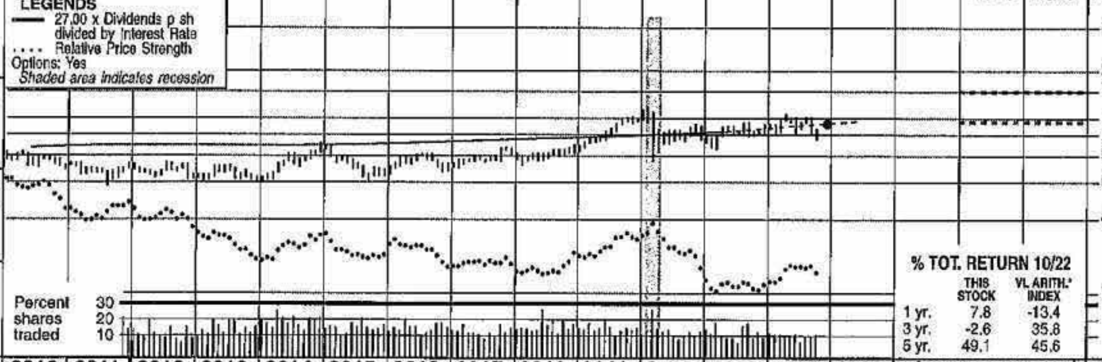
ENTERGY CORP. NYSE-ETR

RECENT PRICE **113.25** | P/E RATIO **17.0** (Trailing: 18.1; Median: 14.0) | RELATIVE P/E RATIO **1.04** | DIV'D YLD **3.8%** | VALUE LINE

TIMELINESS **3** Raised 9/2/22	
SAFETY **2** Raised 12/13/19	
TECHNICAL **4** Lowered 12/9/22	
BETA .95 (1.00 = Market)	

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High: 74.5	74.5	72.6	92.0	90.3	82.1	87.9	90.8	122.1	135.5	115.0	126.8
Low: 57.6	61.6	60.2	60.4	61.3	65.4	69.6	71.9	83.2	75.2	85.8	94.9

LEGENDS
— 27.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2025 | 2026 | 2027

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$99-$158	$129 (15%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	160	(+40%)	12%
Low	115	(Nil)	5%

Institutional Decisions

	1Q2022	2Q2022	3Q2022
to Buy	327	348	348
to Sell	281	260	258
Hld's(000)	179128	184330	184841

Percent shares traded 30 20 10

% TOT. RETURN 10/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	7.8	-13.4
3 yr.	-2.6	35.8
5 yr.	49.1	45.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
53.94	59.47	69.15	56.82	64.27	63.67	57.94	63.86	69.71	64.54	60.55	61.35	58.23	54.63	50.51	57.95	*63.10*	*56.45*	Revenues per sh	*61.50*
10.69	11.73	12.89	13.29	16.54	17.53	15.98	16.25	17.68	17.71	18.72	16.70	16.50	17.19	18.21	17.90	*17.75*	*17.95*	"Cash Flow" per sh	*20.50*
5.36	5.60	6.20	6.30	6.66	7.55	6.02	4.96	5.77	5.81	6.88	5.19	5.88	6.30	6.90	6.87	*6.65*	*6.80*	Earnings per sh A	*8.50*
2.16	2.58	3.00	3.00	3.24	3.32	3.32	3.32	3.32	3.34	3.42	3.50	3.58	3.66	3.74	3.86	*4.10*	*4.30*	Div'd Decl'd per sh B ■ †	*5.10*
9.44	10.29	13.92	12.99	13.33	15.21	18.18	15.73	14.82	16.79	17.28	22.07	22.45	21.72	24.52	30.86	*18.15*	*19.00*	Cap'l Spending per sh	*19.75*
40.45	40.71	42.07	45.54	47.53	50.81	51.73	54.00	55.83	51.89	45.12	44.28	46.78	51.34	54.56	57.42	*60.00*	*63.55*	Book Value per sh C	*74.00*
202.67	193.12	189.36	189.12	178.75	176.36	177.81	178.37	179.24	178.39	179.13	180.52	189.06	199.15	200.24	202.65	*206.00*	*209.00*	Common Shs Outst'g D	*214.00*
14.3	19.3	16.6	12.0	11.6	9.1	11.2	13.2	12.9	12.5	10.9	15.0	13.8	16.5	15.3	15.0	*Bold figures are*		Avg Ann'l P/E Ratio	*16.0*
.77	1.02	1.00	.80	.74	.57	.71	.74	.68	.63	.57	.75	.75	.88	.79	.80	*Value Line*		Relative P/E Ratio	*.90*
2.8%	2.4%	2.9%	4.0%	4.2%	4.9%	4.9%	5.1%	4.5%	4.6%	4.6%	4.5%	4.4%	3.5%	3.6%	3.7%	*estimates*		Avg Ann'l Div'd Yield	*3.7%*

CAPITAL STRUCTURE as of 9/30/22
Total Debt $27606 mill. Due in 5 Yrs $11117 mill.
LT Debt $24635 mill. LT Interest $824.0 mill.
Incl. $54.7 mill. of securitization bonds.
(LT interest earned: 2.8x)
Leases, Uncapitalized Annual rentals $65.3 mill.
Pension Assets-12/21 $6993.1 mill.
Oblig $8409.6 mill.
Pfd Stock $254.4 mill. **Pfd Div'd** $18.3 mill.
200,000 shs. 6.25%-7.5%, $100 par; 250,000 shs. 8.75%, 1.4 mill. shs. 5.375%; all cum., without sinking fund.
Common Stock 203,483,660 shs. **as of 10/31/22**
MARKET CAP: $23.0 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
10302	11391	12495	11513	10846	11074	11009	10879	10114	11743	*13000*	*11800*	Revenues ($mill)	*13150*
1091.9	904.5	1060.0	1061.2	1249.8	950.7	1092.1	1258.2	1406.7	1402.8	*1370*	*1420*	Net Profit ($mill)	*1846*
13.0%	26.7%	37.8%	2.2%	11.3%	1.8%	NMF	NMF	NMF	16.1%	*23.0%*	*23.0%*	Income Tax Rate	*23.0%*
11.9%	10.1%	9.3%	7.4%	8.1%	14.7%	17.5%	16.7%	12.2%	7.1%	*8.0%*	*8.0%*	AFUDC % to Net Profit	*7.0%*
55.8%	55.1%	54.9%	57.8%	63.6%	63.6%	63.2%	62.0%	65.5%	67.6%	*66.5%*	*66.5%*	Long-Term Debt Ratio	*66.0%*
42.9%	43.6%	43.8%	40.8%	35.5%	35.5%	35.9%	37.1%	33.7%	31.7%	*32.5%*	*33.0%*	Common Equity Ratio	*33.5%*
21432	22109	22842	22714	22777	22528	24602	27557	32386	36733	*38050*	*40200*	Total Capital ($mill)	*47300*
27299	27882	28723	27824	27921	29664	31974	35183	38853	42244	*43750*	*45425*	Net Plant ($mill)	*50800*
6.4%	5.4%	6.0%	6.0%	6.9%	5.7%	5.8%	5.9%	5.6%	4.8%	*3.0%*	*4.5%*	Return on Total Cap'l	*5.0%*
11.5%	9.1%	10.3%	11.1%	15.1%	11.6%	12.0%	12.0%	12.6%	11.6%	*9.5%*	*10.5%*	Return on Shr. Equity	*11.5%*
11.6%	9.2%	10.4%	11.2%	15.2%	11.7%	12.2%	12.1%	12.7%	11.9%	*9.5%*	*10.5%*	Return on Com Equity E	*11.5%*
5.2%	3.0%	4.4%	4.8%	7.7%	3.9%	4.9%	5.2%	5.9%	5.2%	*3.5%*	*4.0%*	Retained to Com Eq	*4.5%*
56%	68%	58%	58%	50%	66%	61%	58%	55%	57%	*62%*	*64%*	All Div'ds to Net Prof	*60%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-1.4	-4.1	+3.2
Avg. Indust. Use (MWH)	1070	1017	1015
Avg. Indust. Revs. per KWH(¢)	5.24	4.95	5.91
Capacity at Peak (Mw)	23887	25665	NA
Peak Load, Summer (Mw)	21598	21340	NA
Annual Load Factor (%)	64	62	NA
% Change Customers (yr-end)	+.8	+1.0	+1.0
Fixed Charge Cov. (%)	165	202	243

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-1.0%	-3.5%	*2.0%*
"Cash Flow"	1.0%	-.5%	*2.5%*
Earnings	--	1.5%	*4.0%*
Dividends	1.5%	2.0%	*5.0%*
Book Value	1.5%	1.5%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	2610	2666	3141	2462	10879
2020	2427	2413	2904	2370	10114
2021	2845	2822	3353	2723	11743
2022	2878	3395	4219	*2508*	*13000*
2023	*2950*	*2850*	*3250*	*2750*	*11800*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.32	1.22	1.82	1.94	6.30
2020	.59	1.79	2.59	1.93	6.90
2021	1.66	1.30	2.63	1.28	6.87
2022	1.36	1.78	2.84	*.67*	*6.65*
2023	*1.40*	*1.75*	*2.90*	*.75*	*6.80*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.89	.89	.89	.91	3.58
2019	.91	.91	.91	.93	3.66
2020	.93	.93	.93	.95	3.74
2021	.95	.95	.95	1.01	3.86
2022	1.01	1.01	1.01	1.07	

BUSINESS: Entergy Corporation supplies electricity to 3 million customers through subsidiaries in Arkansas, Louisiana, Mississippi, Texas, and New Orleans (regulated separately from Louisiana). Distributes gas to 206,000 customers in Louisiana. Is selling its last nonutility nuclear unit (shut down 5/22). Electric revenue breakdown: residential, 37%; commercial, 24%; industrial, 27%; other, 12%. Generating sources: gas, 46%; nuclear, 30%; coal, 6%; purchased, 18%. Fuel costs: 32% of revenues. '21 reported depreciation rate: 2.7%. Has 12,400 employees. Chairman & CEO: Leo P. Denault. Incorporated: Delaware. Address: 639 Loyola Avenue, P.O. Box 61000, New Orleans, Louisiana 70161. Telephone: 504-576-4000. Internet: www.entergy.com.

Entergy Corp. recorded solid third-quarter results. Revenues expanded to $4.2 billion, aided by strong growth across its electric services business and higher energy prices. Positives included healthy demand from industrial companies, while population growth across the southern United States was positive. The company also benefited from several rate cases being approved, allowing for more recoveries, and a few projects were placed into service. Still, costs rose at a quick rate, especially those related to fuel costs, while operational maintenance was much higher. Overall, adjusted earnings rose to $2.84 per share during the quarter. The fourth-quarter performance will likely be lackluster as the company faces tough comparisons from 2021, which had cooler-than-usual weather. It exited some non-regulated nuclear operations in Michigan over the past year, and it sold some shares to fund capital expenditures. We estimate adjusted earnings will reach $0.67 per share in the final quarter of 2022.

The long-term outlook is decent. Entergy should gain from population and industrial growth across its coverage area. Additionally, it has filed for several rate cases, including for Entergy New Orleans and Entergy Texas, with a decision on the latter due in the second quarter of 2023. Additionally, the company has been investing in renewable energy projects that will come online in the years ahead, helping to bolster revenues, and regulators could approve more. Costs for fuel and maintenance will likely increase with the added operations. The company has been funding capital expenditures with debt and equity sales, which should limit profit-per-share gains. Bad-debt expenses may well pick up if the economy slows further. We project adjusted earnings per share of $6.80 in 2023 and $8.50 in 2025-2027.

The board raised the quarterly dividend by 6% to $1.07. This payout remains well covered by profits and should expand steadily in the years ahead.

Shares of Entergy Corp. are neutrally ranked for Timeliness. This stock has a good dividend yield and long-term upside potential is subpar. Overall, we think this is best suited for conservative income-seeking accounts.

John E. Seibert III *December 9, 2022*

(A) Diluted EPS. Excl. nonrec. losses: '12, $1.26; '13, $1.14; '14, 56¢; '15, $6.99; '16, $10.14; '17, $2.91; '18, $1.25; '21, $1.33; '22, $1.19. Next earnings report due early Feb. (B) Div'ds historically paid in early Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '21: $35.95/sh. (D) In mill. (E) Rate base: Net original cost. Allowed ROE (blended): 9.95%; earned on avg. com. eq., '21: 12.1%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	45
Earnings Predictability	70

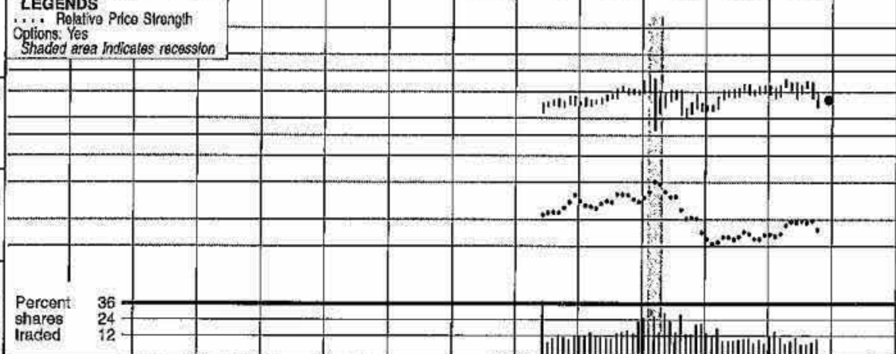
EVERGY, INC. NYSE-EVRG

RECENT PRICE 58.69 | P/E RATIO 16.4 (Trailing: 17.0, Median: NMF) | RELATIVE P/E RATIO 1.01 | DIV'D YLD 4.2% | VALUE LINE

TIMELINESS 3 Raised 9/2/22
SAFETY 2 New 9/14/18
TECHNICAL 3 Lowered 11/18/22
BETA .90 (1.00 = Market)

	2018	2019	2020	2021	2022
High:	61.1	67.8	76.6	69.4	73.1
Low:	50.9	54.6	42.0	51.9	54.1

LEGENDS
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2025 | 2026 | 2027
128 96 80 64 48 40 32 24 16 12

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$53-$88	$71 (20%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	95	(+60%)	16%
Low	70	(+20%)	8%

Institutional Decisions

	1Q2022	2Q2022	3Q2022
to Buy	284	304	305
to Sell	270	252	250
Hld's(000)	196288	194242	193700

Percent shares traded 36 24 12

% TOT. RETURN 10/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-0.9	-13.4
3 yr.	6.1	35.8
5 yr.	—	45.6

Evergy, Inc. was formed through the merger of Great Plains Energy and Westar Energy in June of 2018. Great Plains Energy holders received .5981 of a share of Evergy for each of their shares, and Westar Energy holders received one share of Evergy for each of their shares. The merger was completed on June 4, 2018. Shares of Evergy began trading on the New York Stock Exchange one day later.

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
--	--	--	--	--	--	16.75	22.71	21.66	24.36	24.80	25.20	Revenues per sh	26.50
--	--	--	--	--	--	4.89	7.18	7.06	8.18	8.05	8.40	"Cash Flow" per sh	10.00
--	--	--	--	--	--	2.50	2.79	2.72	3.83	3.55	3.75	Earnings per sh A	4.75
--	--	--	--	--	--	1.74	1.93	2.05	2.18	2.33	2.48	Div'd Decl'd per sh B ■	3.05
--	--	--	--	--	--	4.19	5.34	6.88	8.60	8.60	9.20	Cap'l Spending per sh	9.50
--	--	--	--	--	--	39.26	37.82	38.50	40.32	41.40	42.70	Book Value per sh C	47.50
--	--	--	--	--	--	255.33	226.64	226.84	229.30	230.00	230.00	Common Shs Outst'g D	230.00
--	--	--	--	--	--	22.7	21.8	21.7	16.2	Bold figures are		Avg Ann'l P/E Ratio	17.5
--	--	--	--	--	--	1.23	1.16	1.11	.87	Value Line		Relative P/E Ratio	.95
--	--	--	--	--	--	3.1%	3.2%	3.5%	3.5%	estimates		Avg Ann'l Div'd Yield	3.7%
--	--	--	--	--	--	4275.9	5147.8	4913.4	5586.7	5700	5800	Revenues ($mill)	6100
--	--	--	--	--	--	535.8	669.9	618.3	879.7	835	880	Net Profit ($mill)	1115
--	--	--	--	--	--	9.8%	12.6%	14.1%	11.7%	9.0%	9.0%	Income Tax Rate	9.0%
--	--	--	--	--	--	2.5%	2.5%	5.6%	5.0%	5.0%	6.0%	AFUDC % to Net Profit	5.0%
--	--	--	--	--	--	40.0%	50.6%	51.3%	50.1%	51.5%	51.5%	Long-Term Debt Ratio	53.5%
--	--	--	--	--	--	60.0%	49.4%	48.7%	49.9%	48.5%	48.5%	Common Equity Ratio	46.5%
--	--	--	--	--	--	16716	17337	17924	18542	19675	20175	Total Capital ($mill)	23400
--	--	--	--	--	--	18952	19346	20106	21150	22100	23150	Net Plant ($mill)	26300
--	--	--	--	--	--	4.0%	4.8%	4.5%	5.7%	5.0%	5.5%	Return on Total Cap'l	6.0%
--	--	--	--	--	--	5.3%	7.8%	7.1%	9.5%	8.5%	9.0%	Return on Shr. Equity	10.0%
--	--	--	--	--	--	5.3%	7.8%	7.1%	9.5%	8.5%	9.0%	Return on Com Equity E	10.0%
--	--	--	--	--	--	.6%	2.4%	1.8%	4.1%	3.0%	3.0%	Retained to Com Eq	3.5%
--	--	--	--	--	--	89%	69%	75%	57%	64%	65%	All Div'ds to Net Prof	63%

CAPITAL STRUCTURE as of 9/30/22
Total Debt $11664 mill. Due in 5 Yrs $4388.2 mill.
LT Debt $9197.2 mill. LT Interest $305.5 mill.
Incl. $40.9 mill. finance leases.
(LT interest earned: 3.8x)

Leases, Uncapitalized Annual rentals $18.8 mill.

Pension Assets-12/21 $1714.7 mill.
Oblig $2561.7 mill.

Pfd Stock None

Common Stock 229,536,385 shs.
as of 10/31/22
MARKET CAP: $13.5 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	NA	-3.9	+3.1
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	7.25	7.14	6.94
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	305	286	350

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	--	--	2.5%
"Cash Flow"	--	--	5.0%
Earnings	--	--	7.5%
Dividends	--	--	7.0%
Book Value	--	--	3.5%

QUARTERLY REVENUES ($ mill.)

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1217	1222	1578	1131	5148
2020	1117	1185	1517	1094	4913
2021	1612	1236	1617	1122	5587
2022	1224	1447	1909	1120	5700
2023	1225	1450	1900	1225	5800

EARNINGS PER SHARE A

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.39	.57	1.56	.28	2.79
2020	.31	.59	1.60	.22	2.72
2021	.84	.81	1.95	.23	3.83
2022	.53	.84	1.86	.32	3.55
2023	.60	.80	2.05	.30	3.75

QUARTERLY DIVIDENDS PAID B ■

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.40	.40	.46	.475	1.74
2019	.475	.475	.475	.505	1.93
2020	.505	.505	.505	.535	2.05
2021	.535	.535	.535	.5725	2.18
2022	.5725	.5725	.6125		

BUSINESS: Evergy, Inc. was formed through the merger of Great Plains Energy and Westar Energy in June of 2018. Through its subsidiaries (now doing business under the Evergy name), provides electric service to 1.6 million customers in Kansas and Missouri, including the greater Kansas City area. Electric revenue breakdown: residential, 34%; commercial, 30%; industrial, 11%; wholesale, 13%; other, 12%. Generating sources: coal, 54%; nuclear, 17%; purchased, 29%. Fuel costs: 28% of revenues. '21 reported deprec. rate: 3%. Has 4,900 employees. Chairman: Mark A. Ruelle. President & CEO: David A. Campbell. COO: Kevin E. Bryant. Inc.: Missouri. Address: 1200 Main Street, Kansas City, Missouri 64105. Tel.: 816-556-2200. Internet: www.evergy.com.

Evergy delivered strong financial results in the third quarter. Earnings of $1.86 a share, on revenues of $1.9 billion, both exceeded Wall Street's expectations and increased 75%, and 27% from the last period, respectively. The performance was due primarily to the company's improved transmission margin, along with continued favorable demand in all sectors. Total demand has grown 3% this year and 2.4% in the September-period, driven by increases in industrial demand such as the chemical and oil and gas sectors.

The company raised its 2022 earnings range from $3.43-$3.63 a share to $3.53-$3.63 due to the better-than-expected September-period showing. Management remains committed to its long-term EPS growth-rate target of 6%-8% annualy. We have adjusted our top-line estimate which now stands at $5.7 billion, up from our previous call of $5.4 billion. In 2023, we are forecasting revenues of $5.8 billion and earnings of $3.75 per share.

Evergy has hiked its dividend by 7%. The dividend yield of 4.2%, which is solid for a utility should appeal to income-oriented investors. Management is targeting a dividend growth rate in line with earnings at a 60%-70% payout.

The company hopes to get approval on its acquisition of the Permisson Creek Wind Farm by year end. The $250 million investment will boost the renewable energy business and assist the utility in its goal of net-zero carbon emissions by 2045.

Evergy shares have underperformed of late. The stock has declined more than 16% in value over the past three months, alongside losses by many of its peers. The utility industry has struggled recently due to the challenging interest-rate environment. Higher yields on Treasuries have prompted a growing number of income-oriented investors to enter the bond market, and the competition has not augured well for utilities. Due to its recent price struggles, capital appreciation potential over the 18-month span, and 3- to 5-year period have improved since our last review. Also, these shares are ranked to mirror the broader market averages over the next year. But the dividend continues to be the main attraction here.

Zachary J. Hodgkinson December 9, 2022

(A) Diluted earnings. '19 EPS don't sum to full-year total due to rounding. Next earnings report due late February. (B) Dividends paid in mid-March, June, September, and December. ■ Dividend reinvestment plan available. (C) Incl. intangibles. In '21: $4,327.7 mill., $18.87/sh. (D) In millions. (E) Rate base: Original cost depreciated. Rate allowed on common equity in Missouri in '18: none specified; in Kansas in '18: 9.3%; earned on average common equity, '21: 9.8%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	85
Price Growth Persistence	35
Earnings Predictability	NMF

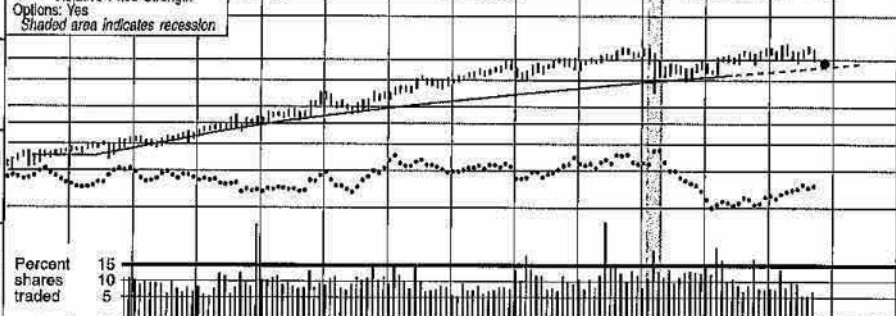
IDACORP, INC. NYSE-IDA

RECENT PRICE **96.53** | P/E RATIO **19.2** (Trailing: 20.3; Median: 19.0) | RELATIVE P/E RATIO **1.31** | DIV'D YLD **3.1%** | VALUE LINE

TIMELINESS 4 Lowered 9/23/22
SAFETY 1 Raised 1/22/21
TECHNICAL 2 Raised 10/14/22
BETA .80 (1.00 = Market)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	42.7	45.7	54.7	70.1	70.5	83.4	100.0	102.4	114.0	113.6	113.8	118.9
Low:	33.9	38.2	43.1	50.2	55.4	65.0	77.5	79.6	89.3	69.1	85.3	95.8

LEGENDS
—— 29.4 x Dividends p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2025 | 2026 | 2027

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$94-$148	$121 (25%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	130	(+35%)	10%
Low	105	(+10%)	5%

Institutional Decisions

	4Q2021	1Q2022	2Q2022
to Buy	208	181	174
to Sell	137	164	164
Hld's(000)	39410	39894	40518

Percent shares traded 15 10 5

% TOT. RETURN 9/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-1.5	-18.2
3 yr.	-4.9	24.1
5 yr.	28.2	32.9

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
21.23	19.51	20.47	21.92	20.97	20.55	21.55	24.81	25.51	25.23	25.04	26.76	27.19	26.70	26.77	28.86	*28.40*	*28.65*	Revenues per sh	*34.25*
4.58	4.11	4.27	5.07	5.35	5.84	5.93	6.29	6.58	6.70	6.86	7.50	7.85	8.07	8.19	8.41	*8.30*	*8.85*	"Cash Flow" per sh	*10.40*
2.35	1.86	2.18	2.64	2.95	3.36	3.37	3.64	3.85	3.87	3.94	4.21	4.49	4.61	4.69	4.85	*5.00*	*5.25*	Earnings per sh A	*6.00*
1.20	1.20	1.20	1.20	1.20	1.20	1.37	1.57	1.76	1.92	2.08	2.24	2.40	2.56	2.72	2.88	*3.05*	*3.25*	Div'd Decl'd per sh B ■ †	*4.00*
5.16	6.39	5.19	5.26	6.85	6.76	4.78	4.68	5.45	5.84	5.89	5.66	5.51	5.53	6.16	5.94	*10.15*	*14.20*	Cap'l Spending per sh	*10.10*
25.77	26.79	27.76	29.17	31.01	33.19	35.07	36.94	38.85	40.88	42.74	44.65	47.01	48.88	50.73	52.82	*54.65*	*56.45*	Book Value per sh C	*63.95*
43.63	45.06	46.92	47.90	49.41	49.95	50.16	50.23	50.27	50.34	50.40	50.42	50.42	50.42	50.46	50.52	*50.70*	*51.00*	Common Shs Outst'g D	*52.00*
15.1	18.2	13.9	10.2	11.8	11.5	12.4	13.4	14.7	16.2	19.1	20.6	20.5	22.3	19.9	20.8	*Bold figures are*		Avg Ann'l P/E Ratio	*19.5*
.82	.97	.84	.68	.75	.72	.79	.75	.77	.82	1.00	1.04	1.11	1.19	1.02	1.14	*Value Line*		Relative P/E Ratio	*1.10*
3.4%	3.5%	4.0%	4.5%	3.4%	3.1%	3.3%	3.2%	3.1%	3.1%	2.8%	2.6%	2.6%	2.5%	2.9%	2.9%	*estimates*		Avg Ann'l Div'd Yield	*3.4%*

CAPITAL STRUCTURE as of 6/30/22
Total Debt $2150.7 mill. Due in 5 Yrs $325.0 mill.
LT Debt $2075.7 mill. LT Interest $100.0 mill.
(LT interest earned: 3.8x)

Pension Assets-12/21 $984.5 mill.
Oblig $1346.5 mill.

Pfd Stock None

Common Stock 50,560,040 shs.
as of 7/29/22

MARKET CAP: $4.9 billion (Mid Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
1080.7	1246.2	1282.5	1270.3	1262.0	1349.5	1370.8	1346.4	1350.7	1458.1	*1440*	*1460*	Revenues ($mill)	*1780*
168.9	182.4	193.5	194.7	198.3	212.4	226.8	232.9	237.4	245.6	*255*	*270*	Net Profit ($mill)	*310*
13.4%	28.3%	8.0%	19.0%	15.5%	18.6%	7.1%	9.5%	10.8%	13.1%	*13.0%*	*13.0%*	Income Tax Rate	*13.0%*
20.3%	12.3%	13.6%	16.3%	16.3%	13.9%	15.2%	16.2%	17.3%	17.7%	*20.0%*	*21.0%*	AFUDC % to Net Profit	*16.0%*
45.5%	46.6%	45.3%	45.6%	44.8%	43.7%	43.6%	41.3%	43.9%	42.8%	*43.5%*	*47.5%*	Long-Term Debt Ratio	*50.0%*
54.5%	53.4%	54.7%	54.4%	55.2%	56.3%	56.4%	58.7%	56.1%	57.2%	*56.5%*	*52.5%*	Common Equity Ratio	*50.0%*
3225.4	3465.9	3567.6	3783.3	3898.5	3997.5	4205.1	4201.3	4560.4	4669.1	*4920*	*5505*	Total Capital ($mill)	*6675*
3536.0	3665.0	3833.5	3992.4	4172.0	4283.9	4395.7	4531.5	4709.5	4901.8	*5300*	*5800*	Net Plant ($mill)	*6730*
6.5%	6.4%	6.6%	6.2%	6.1%	6.3%	6.4%	6.5%	6.1%	6.2%	*6.0%*	*5.5%*	Return on Total Cap'l	*5.5%*
9.6%	9.9%	9.9%	9.5%	9.2%	9.4%	9.6%	9.4%	9.3%	9.2%	*9.0%*	*9.0%*	Return on Shr. Equity	*9.0%*
9.6%	9.9%	9.9%	9.5%	9.2%	9.4%	9.6%	9.4%	9.3%	9.2%	*9.0%*	*9.0%*	Return on Com Equity E	*9.0%*
5.7%	5.6%	5.4%	4.8%	4.3%	4.4%	4.4%	4.2%	3.9%	3.7%	*3.5%*	*3.5%*	Retained to Com Eq	*3.0%*
41%	43%	46%	50%	53%	53%	54%	56%	58%	60%	*61%*	*62%*	All Div'ds to Net Prof	*67%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-.3	+2.0	+3.9
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	5.32	5.38	5.62
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	3242	3392	3751
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+2.5	+2.7	+2.8
Fixed Charge Cov. (%)	307	313	334

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	2.5%	1.5%	*4.0%*
"Cash Flow"	4.5%	4.0%	*4.0%*
Earnings	4.5%	4.0%	*4.0%*
Dividends	8.5%	7.0%	*6.5%*
Book Value	5.0%	4.5%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	350.3	316.9	386.3	292.9	1346.4
2020	291.0	318.8	425.3	315.6	1350.7
2021	316.1	360.1	446.9	335.0	1458.1
2022	344.3	358.7	*425*	*312.0*	*1440*
2023	*350*	*360*	*430*	*320*	*1460*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.84	1.05	1.78	.93	4.61
2020	.74	1.19	2.02	.74	4.69
2021	.89	1.38	1.93	.65	4.85
2022	.91	1.27	*2.00*	*.82*	*5.00*
2023	*.95*	*1.40*	*2.05*	*.85*	*5.25*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.59	.59	.59	.63	2.40
2019	.63	.63	.63	.67	2.56
2020	.67	.67	.67	.71	2.72
2021	.71	.71	.71	.75	2.88
2022	.75	.75	.75		

BUSINESS: IDACORP, Inc. is a holding company for Idaho Power Company, a regulated electric utility that serves 604,000 customers throughout a 24,000-square-mile area in southern Idaho and eastern Oregon (population: 1.3 million). Most of the company's revenues are derived from the Idaho portion of its service area. Revenue breakdown: residential, 45%; commercial, 24%; industrial, 15%; irrigation, 13%; other, 3%. Generating sources: hydro, 30%; coal, 17%; gas, 15%; purchased, 38%. Fuel costs: 36% of revenues. '21 reported depreciation rate: 2.9%. Has 2,000 employees. Chairman: Richard J. Dahl. President & CEO: Lisa Grow. Incorporated: Idaho. Address: 1221 W. Idaho St., Boise, Idaho 83702. Telephone: 208-388-2200. Internet: www.idacorpinc.com.

Annual earnings growth at IDACORP is pegged to be 3% and 5%, respectively, in 2022 and 2023. Weather-related usage and transmission wheeling revenues are trending higher, aided by solid population growth in the areas that IDA serves. Air conditioning and irrigation have been primary drivers and should be for the foreseeable future. Too, the likelihood of a rate increase is certainly on the table (more color below) for next year, though nothing is set in stone on that front. With that, we think share net can climb to $5.00 this year, followed by an expected 5% annual increase to $5.25 in 2023.

One would need to go back to 2011 for the most recent rate case in Idaho Power's jurisdiction. That is more than a decade of no rate applications, a period marked by a lofty influx of people into IDA's areas of operation. Management has capital budget plans that will require funding, notably the increased stake it is taking in a transmission line and the financing of larger battery storage capabilities. Dipping in to debt markets will probably be the first move, even as rates are heading north, with an issuance of equity on the slate for 2024.

Capital expenditures are primed for an uptick next year, but should recede after that. For 2022, we look for the cap ex number to come in around $515 million. However, in 2023, we have that amount climbing to $725 million, with the vast majority earmarked for new capacity resources. A recent integrated resources plan came back stating that IDA could have a 125 MW capacity deficit by 2025. This is where using the battery storage comes into the situation. Too, the company's exit from coal-fired manufacturing will require adding significant generation capabilities. A new transmission line will help, but it will not come cheap.

IDACORP's shares are of high quality, but we are not recommending them at this time. For starters, the issue's yield is noticeably below what we deem as average for the utility stocks in our coverage universe. Add to this, the equity has dipped one notch to Below Average (4) on our Timeliness Ranking Scale. Lastly, total return potential three to five years hence does little to quicken the pulse.

Erik M. Manning *October 21, 2022*

(A) Diluted EPS. Excl. nonrecurring gain: '06, 17¢. '19 earnings don't sum due to rounding. Next earnings report due last week of October. (B) Dividends historically paid in late Feb., May, Aug., and Nov. ■ Dividend reinvestment plan available. † Shareholder investment plan available. (C) Incl. intangibles. In '21: $1,462.4 mill., $28.95/sh. (D) In millions. (E) Rate base: Net original cost. Rate allowed on common equity in '12: 10% (imputed); earned on avg. com. eq., '21: 9.4%. Regulatory Climate: Above Average.

Company's Financial Strength	A+
Stock's Price Stability	100
Price Growth Persistence	75
Earnings Predictability	100

NEXTERA ENERGY NYSE-NEE

RECENT PRICE 77.50 | P/E RATIO 25.6 (Trailing: 27.6; Median: 21.0) | RELATIVE P/E RATIO 1.66 | DIV'D YLD 2.4% | VALUE LINE

TIMELINESS 4 Lowered 9/30/22
SAFETY 1 Raised 2/16/18
TECHNICAL 1 Raised 9/30/22
BETA .90 (1.00 = Market)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	15.3	18.1	22.4	27.7	28.2	33.0	39.8	46.1	61.3	83.3	93.7	93.6
Low:	12.3	14.6	17.5	21.0	23.4	25.5	29.3	36.3	42.2	43.7	68.3	67.2

18-Month Target Price Range

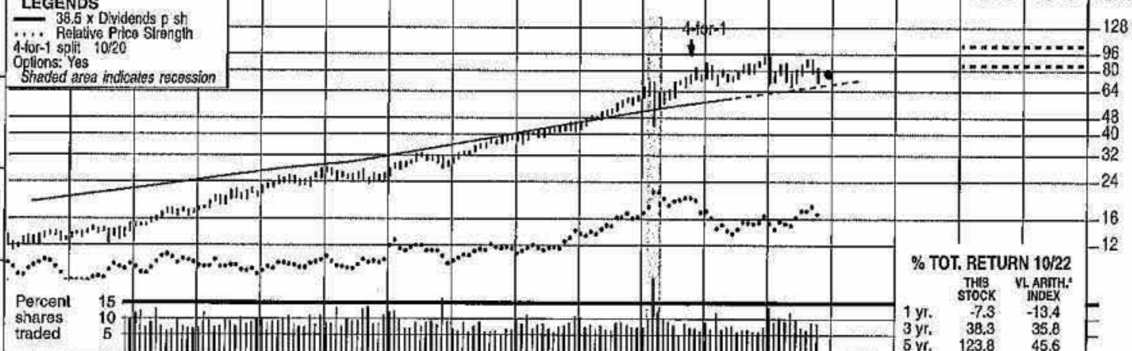
Low-High	Midpoint (% to Mid)
$66-$136	$101 (30%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	105	(+35%)	10%
Low	85	(+10%)	5%

Institutional Decisions

	4Q2021	1Q2022	2Q2022
to Buy	1210	1155	1104
to Sell	831	944	949
Hld's(000)	1508954	1500092	1514051



% TOT. RETURN 10/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-7.3	-13.4
3 yr.	38.3	35.8
5 yr.	123.8	45.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
9.69	9.37	10.03	9.45	9.10	9.22	8.41	8.70	9.61	9.48	8.63	9.13	8.75	9.82	9.18	8.70	10.85	12.60	Revenues per sh	14.75
1.69	1.71	2.01	2.19	2.41	2.32	2.17	2.63	3.03	3.23	3.24	3.03	3.84	4.22	4.52	4.70	5.15	5.40	"Cash Flow" per sh	6.75
.81	.82	1.02	.99	1.19	1.21	1.14	1.21	1.40	1.52	1.45	1.63	1.67	1.94	2.31	2.55	2.90	3.15	Earnings per sh A	4.10
.38	.41	.45	.47	.50	.55	.60	.66	.73	.77	.87	.98	1.11	1.25	1.40	1.54	1.70	1.87	Div'd Decl'd per sh B ■ †	2.50
2.31	3.08	3.20	3.63	3.47	3.98	5.58	3.84	3.96	4.54	5.15	5.70	6.80	6.29	7.45	8.19	8.10	8.40	Cap'l Spending per sh	10.00
6.12	6.59	7.14	7.84	8.59	8.98	9.47	10.37	11.24	12.24	13.00	14.97	17.86	18.92	18.63	18.95	19.70	22.75	Book Value per sh C	27.25
1621.8	1629.4	1635.7	1654.5	1683.4	1664.0	1696.0	1740.0	1772.0	1844.0	1872.0	1884.0	1912.0	1956.0	1960.0	1963.0	1980.0	2025.0	Common Shs Outst'g D	2025.0
13.7	18.9	14.5	13.4	10.8	11.5	14.4	16.6	17.3	16.9	20.7	21.6	24.8	26.8	28.9	31.3	Bold figures are		Avg Ann'l P/E Ratio	23.5
.74	1.00	.87	.89	.69	.72	.92	.93	.91	.85	1.09	1.09	1.34	1.43	1.48	1.68	Value Line		Relative P/E Ratio	1.30
3.4%	2.7%	3.0%	3.5%	3.9%	4.0%	3.6%	3.3%	3.0%	3.0%	2.9%	2.8%	2.7%	2.4%	2.1%	1.9%	estimates		Avg Ann'l Div'd Yield	2.6%
						14256	15136	17021	17486	16155	17195	16727	19204	17997	17069	21500	25500	Revenues ($mill)	30000
						1911.0	2062.0	2465.0	2752.0	2693.0	3074.0	3200.0	3769.0	4552.0	5021.0	5750	6335	Net Profit ($mill)	8330
						26.6%	26.9%	32.3%	30.8%	29.3%	24.4%	28.6%	11.7%	13.0%	15.0%	15.0%	15.0%	Income Tax Rate	15.0%
						10.8%	7.0%	6.7%	6.9%	8.2%	6.7%	6.6%	3.9%	3.8%	5.3%	5.0%	4.0%	AFUDC % to Net Profit	4.0%
						59.1%	57.1%	55.0%	54.2%	53.3%	52.7%	44.0%	50.4%	53.5%	57.8%	58.5%	56.5%	Long-Term Debt Ratio	56.0%
						40.9%	42.9%	45.0%	45.8%	46.7%	47.3%	56.0%	49.6%	46.5%	42.2%	41.5%	43.5%	Common Equity Ratio	44.0%
						39245	42009	44283	49255	52159	59671	60926	74548	78457	88162	93950	105850	Total Capital ($mill)	126100
						49413	52720	55705	61386	66912	72416	70334	82010	91803	99348	110925	123300	Net Plant ($mill)	165200
						6.2%	6.2%	7.0%	6.8%	6.3%	6.3%	6.3%	6.0%	6.5%	6.4%	7.0%	6.5%	Return on Total Cap'l	7.5%
						11.9%	11.4%	12.4%	12.2%	11.1%	10.9%	9.4%	10.2%	12.5%	13.5%	15.0%	13.5%	Return on Shr. Equity	15.0%
						11.9%	11.4%	12.4%	12.2%	11.1%	10.9%	9.4%	10.2%	12.5%	13.5%	15.0%	13.5%	Return on Com Equity E	15.0%
						5.6%	5.2%	6.0%	6.1%	4.4%	4.4%	3.2%	3.7%	5.0%	5.4%	6.0%	5.5%	Retained to Com Eq	6.0%
						53%	54%	51%	50%	60%	60%	66%	64%	60%	60%	58%	59%	All Div'ds to Net Prof	61%

CAPITAL STRUCTURE as of 9/30/22
Total Debt $64825 mill. Due in 5 Yrs $26264 mill.
LT Debt $54670 mill. LT Interest $1402 mill.

(Total interest coverage: 4.6x)

Pension Assets-12/21 $5688 mill. Oblig $3445 mill.

Pfd Stock None

Common Stock 1,964,779,183 shs. as of 6/30/22

MARKET CAP: $152.3 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	NA	NA	NA
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.8	+1.5	+1.5
Fixed Charge Cov. (%)	230	235	203

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	--	--	8.0%
"Cash Flow"	7.0%	7.0%	7.0%
Earnings	7.0%	9.5%	10.5%
Dividends	10.5%	12.0%	10.0%
Book Value	8.5%	9.0%	6.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	4075	4970	5572	4587	19204
2020	4613	4204	4785	4395	17997
2021	3726	3927	4370	5046	17069
2022	2890	5183	6719	6708	21500
2023	4800	5770	7455	7475	25500

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.35	.64	.45	.50	1.94
2020	.59	.65	.67	.40	2.31
2021	.67	.71	.75	.41	2.55
2022	.74	.81	.85	.50	2.90
2023	.80	.88	.92	.55	3.15

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.2775	.2775	.2775	.2775	1.11
2019	.3125	.3125	.3125	.3125	1.25
2020	.35	.35	.35	.35	1.40
2021	.385	.385	.385	.385	1.54
2022	.425	.425	.425		

BUSINESS: NextEra Energy, Inc. is a holding company for Florida Power & Light Company (FPL), which provides electricity to roughly 5.8 mill. customers in eastern, southern, & northwestern FL. NextEra Energy Resources is a nonregulated power generator with nuclear, gas, & renewables. Has 55% stake in NextEra Energy Partners. Acquired Gulf Power 1/19; Florida City Gas 7/18. Rev.: residential, 55%; commercial, 33%; industrial & other, 12%. Generating sources: gas, 73%; nuclear, 22%; other, 3%; purchased, 2%. Fuel costs: 27% of revenues. '21 depreciation rate: 3.3%. Has 15,000 employees. Chairman, President and CEO: John W. Ketchum. Inc.: Florida. Address: 700 Universe Blvd., Juno Beach, FL 33408. Tel.: 561-694-4000. Internet: www.nexteraenergy.com.

NextEra Energy is well situated for sustained earnings growth. Its utility, Florida Power & Light Company (FPL), is benefiting from a very healthy local economy. The Sunshine State continues to attract strong migration, and is experiencing one of the fastest U.S. population growth rates. Florida's unemployment rate of 2.7% remains below the national average and at its lowest level in over 15 years. Meanwhile, distribution and transmission (D&T) expansion, and reliability/hardiness projects in storm-challenged Florida, are leading to rapid growth in the utility's rate base (property, plant, and equipment on which utilitites are allowed to earn an economic rate of return). FPL's territory did exceptionally well in keeping the power on and/or getting it back up following Hurricane Ian. That's going to help keep the reliability/hardiness program going strong. It's also notable that, as part of NextEra's 2021 settlement agreement with regulators, a sustained increase in 30-year Treasury Bond yields has triggered an increase in the authorized return on equity midpoint from 10.6% to 10.8%.

Renewable energy is a burgeoning market for the company and should be bolstered by the Inflation Reduction Act (IRA). FPL continues to expand its regulated solar capacity within its rate base, and the company's nonregulated subsidiary, NextEra Energy Resources, is a major player in renewable energy across the U.S. That business unit has been growing nicely in recent quarters. The company has 55% ownership in NextEra Energy Partners, LP (NYSE: NEP), which is heavily invested in renewables across 19 states. It's growing at a double-digit clip, while rapidly increasing its dividend to partners. Tax incentives for renewables were set to expire after 2025, but the IRA is expected to help keep this market flourishing for decades to come.

NextEra Energy shares offer appealing intermediate-term total returns. The below-average (4) Timeliness rank means it's likely not appropriate for accounts with an investment horizon of less than one year. Investors with a conservative bent and a dividend-growth focus should find this high-quality issue an attractive addition to their portfolios.

Anthony J. Glennon *November 11, 2022*

(A) Diluted EPS. Excl. nonrecurring gains (losses): '11, (6¢); '13, (20¢); '16, 12¢; '17, $1.22¢; '18, $1.80; '20, (83¢); '21, (74¢); 1Q-3Q '22, ($1.07); disc. ops.: '13, 11¢. EPS may not some to full yr. due to rounding. Next egs. report due late Jan. (B) Div'ds historically paid in mid-Mar., mid-June, mid-Sept., & mid-Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '21: $5.94/sh. (D) In mill., adj. for stock split. (E) Rate all'd on com. eq. in '22 (FPL): 9.7%-11.7%; Regulatory Climate: Average.

Company's Financial Strength	A+
Stock's Price Stability	85
Price Growth Persistence	95
Earnings Predictability	85

NORTHWESTERN NDQ-NWE

RECENT PRICE **49.48** | P/E RATIO **14.5** (Trailing: 14.9 / Median: 17.0) | RELATIVE P/E RATIO **0.99** | DIV'D YLD **5.2%** | VALUE LINE

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High: 36.6 / Low: 27.4	38.0 / 33.0	47.2 / 35.1	58.7 / 42.6	59.7 / 48.4	63.8 / 52.2	64.5 / 55.7	65.7 / 50.0	76.7 / 57.3	80.5 / 45.1	70.8 / 53.2	63.1 / 49.1

TIMELINESS **5** Lowered 9/9/22

SAFETY **2** Raised 7/27/18

TECHNICAL **3** Raised 10/21/22

BETA .90 (1.00 = Market)

LEGENDS
— 24.4 x Dividends p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
\$46-\$69	\$58 (15%)

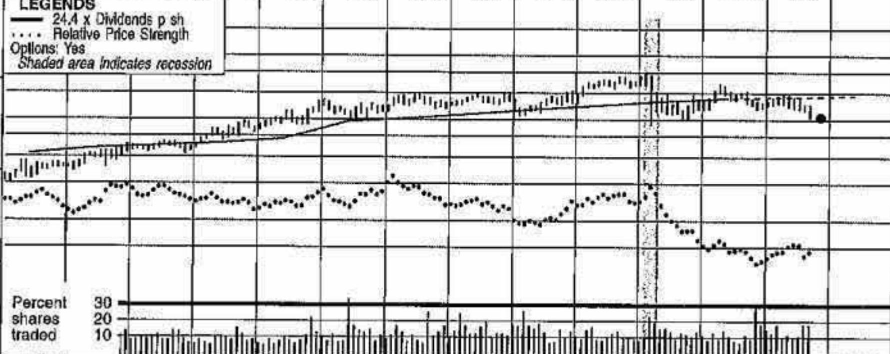
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+50%)	15%
Low	55	(+10%)	8%

Institutional Decisions

	4Q2021	1Q2022	2Q2022
to Buy	170	154	140
to Sell	105	111	121
Hld's(000)	56973	57800	56756

Percent shares traded 30 20 10



Target Price Range 2025 | 2026 | 2027

128 96 80 64 48 40 32 24 16 12

% TOT. RETURN 9/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-10.1	-18.2
3 yr.	-25.6	24.1
5 yr.	5.3	32.9

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
31.49	30.79	35.09	31.72	30.86	30.80	28.76	29.80	25.68	25.21	26.01	26.45	23.81	24.93	23.70	25.38	*24.15*	*23.55*	Revenues per sh	*25.75*
3.62	3.70	4.40	4.62	4.76	5.42	5.18	5.45	5.39	5.92	6.74	6.76	6.96	7.07	6.86	6.92	*6.70*	*6.85*	"Cash Flow" per sh	*8.00*
1.31	1.44	1.77	2.02	2.14	2.53	2.26	2.46	2.99	2.90	3.39	3.34	3.40	3.53	3.21	3.50	*3.35*	*3.56*	Earnings per sh A	*4.00*
1.24	1.28	1.32	1.34	1.36	1.44	1.48	1.52	1.60	1.92	2.00	2.10	2.20	2.30	2.40	2.48	*2.52*	*2.56*	Div'd Decl'd per sh B ■ †	*2.68*
2.81	3.00	3.47	5.26	6.30	6.20	5.89	5.95	5.76	5.89	5.96	5.60	5.64	6.26	8.02	8.03	*10.05*	*9.10*	Cap'l Spending per sh	*6.50*
20.65	21.12	21.25	21.86	22.64	23.68	25.09	26.60	31.50	33.22	34.68	36.44	38.60	40.42	41.10	43.28	*44.60*	*46.30*	Book Value per sh C	*50.00*
35.97	38.97	35.93	36.00	36.23	36.28	37.22	38.75	46.91	48.17	48.33	49.37	50.32	50.45	50.59	54.06	*58.00*	*62.00*	Common Shs Outst'g D	*62.00*
26.0	21.7	13.9	11.5	12.9	12.6	15.7	16.9	16.2	18.4	17.2	17.8	16.8	19.9	18.6	17.4	*Bold figures are*		Avg Ann'l P/E Ratio	*16.5*
1.40	1.15	.84	.77	.82	.79	1.00	.95	.85	.93	.90	.90	.91	1.06	.96	.94	*Value Line*		Relative P/E Ratio	*.90*
3.6%	4.1%	5.4%	5.7%	4.9%	4.5%	4.2%	3.7%	3.3%	3.6%	3.4%	3.5%	3.9%	3.3%	4.0%	4.1%	*estimates*		Avg Ann'l Div'd Yield	*4.1%*
						1070.3	1154.5	1204.9	1214.3	1257.2	1305.7	1198.1	1257.9	1198.7	1372.3	*1400*	*1460*	Revenues (\$mill)	*1600*
						83.7	94.0	120.7	138.4	164.2	162.7	171.1	179.3	162.6	181.6	*190*	*215*	Net Profit (\$mill)	*250*
						9.6%	13.2%	--	13.7%	--	7.6%	--	1.6%	1.6%	.9%	*1.5%*	*3.0%*	Income Tax Rate	*12.0%*
						9.4%	8.7%	8.9%	9.8%	4.3%	5.2%	3.4%	4.6%	6.0%	14.9%	*16.0%*	*14.0%*	AFUDC % to Net Profit	*10.0%*
						53.8%	53.5%	53.4%	53.1%	52.0%	50.2%	52.2%	52.5%	52.8%	52.2%	*50.0%*	*49.5%*	Long-Term Debt Ratio	*49.0%*
						46.2%	46.5%	46.6%	46.9%	48.0%	49.8%	47.8%	47.5%	47.2%	47.8%	*50.0%*	*50.5%*	Common Equity Ratio	*51.0%*
						2020.7	2215.7	3168.0	3408.6	3493.9	3614.5	4064.6	4289.8	4409.1	4893.1	*5195*	*5675*	Total Capital (\$mill)	*6050*
						2435.6	2690.1	3758.0	4059.5	4214.9	4358.3	4521.3	4700.9	4952.9	5247.2	*5630*	*5980*	Net Plant (\$mill)	*6550*
						5.5%	5.5%	4.8%	5.2%	5.9%	5.6%	5.2%	5.2%	4.6%	4.6%	*4.5%*	*4.5%*	Return on Total Cap'l	*5.0%*
						9.0%	9.1%	8.2%	8.6%	9.8%	9.0%	8.8%	8.8%	7.8%	7.8%	*7.5%*	*7.5%*	Return on Shr. Equity	*8.0%*
						9.0%	9.1%	8.2%	8.6%	9.8%	9.0%	8.8%	8.8%	7.8%	7.8%	*7.5%*	*7.5%*	Return on Com Equity E	*8.0%*
						3.2%	3.5%	3.8%	3.0%	4.1%	3.4%	3.2%	3.1%	2.0%	2.3%	*2.0%*	*2.0%*	Retained to Com Eq	*2.5%*
						65%	61%	54%	65%	58%	62%	64%	64%	74%	71%	*75%*	*72%*	All Div'ds to Net Prof	*67%*

CAPITAL STRUCTURE as of 6/30/22
Total Debt \$2533.4 mill. Due in 5 Yrs \$1037.4 mill.
LT Debt \$2530.4 mill. LT Interest \$87.8 mill.
Incl. \$11.9 mill. finance leases.
(Total Interest Coverage: 2.7x)

Pension Assets-12/21 \$605.5 mill. Oblig \$696.8 mill.

Pfd Stock None

Common Stock 56,150,050 shs. as of 7/22/22

MARKET CAP: \$2.8 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	+4.6	-4.4	+.7
Avg. Indust. Use (MWH)	37808	33526	31792
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	2237	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.2	+1.2	+1.6
Fixed Charge Cov. (%)	284	237	252

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-2.5%	-1.0%	.5%
"Cash Flow"	3.5%	3.0%	2.5%
Earnings	4.5%	2.0%	2.5%
Dividends	5.5%	5.5%	2.0%
Book Value	6.0%	4.5%	3.0%

Cal-endar	QUARTERLY REVENUES (\$ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	384.2	270.7	274.8	328.2	1257.9
2020	335.3	269.4	280.6	313.4	1198.7
2021	400.8	298.2	326.0	347.3	1372.3
2022	394.5	323.0	*330.5*	*352*	*1400*
2023	*415*	*330*	*345*	*370*	*1460*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.44	.49	.42	1.18	3.53
2020	1.00	.43	.58	1.21	3.21
2021	1.24	.59	.70	.97	3.50
2022	1.08	.58	*.64*	*1.05*	*3.35*
2023	*1.15*	*.60*	*.70*	*1.10*	*3.55*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.55	.55	.55	.55	2.20
2019	.575	.575	.575	.575	2.30
2020	.60	.60	.60	.60	2.40
2021	.62	.62	.62	.62	2.48
2022	.63	.63	.63		

BUSINESS: NorthWestern Corporation (doing business as NorthWestern Energy) supplies electricity & gas in the Upper Midwest and Northwest, serving 456,000 electric customers in Montana and South Dakota and 298,000 gas customers in Montana (85% of gross margin), South Dakota (14%), and Nebraska (1%). Electric revenue breakdown: residential, 43%; commercial, 49%; industrial, 4%; other, 4%. Generating sources: coal, 28%; hydro, 27%; wind, 6%; other, 4%; purchased, 35%. Fuel costs: 31% of revenues. '21 reported deprec. rate: 2.8%. Has 1,500 employees. Chairman: Dana J. Dykhouse. CEO: Robert C. Rowe. President & COO: Brian B. Bird. Inc.: DE. Address: 3010 West 69th Street, Sioux Falls, SD 57108. Tel.: 605-978-2900. Internet: www.northwesternenergy.com.

NorthWestern shares have flatlined for years, commensurate with EPS. Since 2015, this issue has mainly traded within the \$50-\$60 price range, breaking out briefly from time to time. While net profits have grown gradually over the past several years (the 2016-2022 average annual rate is 2%), shares outstanding have also risen, diluting per-share gains. The main constraint, besides dilution, has been years of underearning the utility's allowable ROE. This is largely due to the relative constraints of the rate-relief mechanisms available in the company's utility territories, which results in regulatory lag. In other words, the company foots the bill for grid maintenance and upgrades but has to justify it and wait for the payback.

Management has a solid plan in place that should help reignite growth. In an effort to become less reliant on purchased power, while modernizing and shoring up reliability, the company is looking to add significant gas-fired capacity in both South Dakota and Montana. An \$83 million, 58-megawatt plant in South Dakota was completed in the second quarter. And in April, NWE broke ground on a \$275 million, 175-mw facility in Montana, expected to be operational by late 2023. Financing is via a \$200 million equity offering (\$53.50 a share) completed in fourth quarter 2021, with \$300 million more expected in early 2023 via a forward sale.

Results depend on an upcoming general rate case decision. NWE has filed its case, and likely will obtain rate relief early next year. The company is also asking for pricing mechanisms that would help alleviate regulatory lag. This may be a tough sell in a historically difficult regulatory environment. Assuming the capacity expansion is allowed to proceed, it would lift the rate base and help to narrow the gap between NWE's earned and allowable ROE. Our projections assume an annual growth rate in share net from 2023 to mid-decade of 4%. It's somewhat below the industry average, yet significantly better than what's transpired in recent years.

This issue is untimely. However, at the recent valuation there may be some appeal for utility investors seeking outsized income. The yield is 115 basis points above the electric utility industry median.

Anthony J. Glennon *October 21, 2022*

(A) Diluted EPS. Excl. nonrec. gains/(losses): '12, 40¢; '15, 27¢; '18, 52¢; '19, 45¢; '20, (15¢); '21, 10¢; Q1-Q2 '22, (4¢). '20 EPS don't sum due to rounding. Next egs. report due late Oct. (B) Div'ds historically paid in late Mar., June, Sept. & Dec. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. def'd charges. In '21: \$19.39/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in MT in '19 (elec.): 9.65%; in '17 (gas): 9.55%; in SD in '15: none specified; in NE in '07: 10.4%. Regulatory Climate: Below Average.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	40
Earnings Predictability	90

OGE ENERGY CORP. NYSE-OGE

RECENT PRICE 39.75 | P/E RATIO 18.0 (Trailing: 17.5; Median: 17.0) | RELATIVE P/E RATIO 1.10 | DIV'D YLD 4.2% | VALUE LINE

TIMELINESS 3 Raised 5/20/22

SAFETY 2 Lowered 12/18/15

TECHNICAL 3 Lowered 12/9/22

BETA 1.00 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$33-$51	$42 (5%)

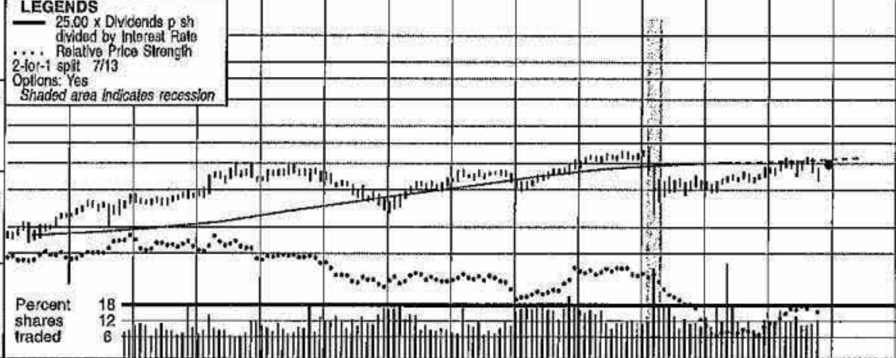
2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+40%)	12%
Low	40	(Nil)	4%

Institutional Decisions

	1Q2022	2Q2022	3Q2022
to Buy	226	218	185
to Sell	170	182	192
Hld's(000)	129869	136256	136256

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	28.6	30.1	40.0	39.3	36.5	34.2	37.4	41.8	45.8	46.4	38.6	42.9
Low:	20.3	25.1	27.7	32.8	24.2	23.4	32.6	29.6	38.0	23.0	29.2	33.3



% TOT. RETURN 10/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	12.3	-13.4
3 yr.	-3.1	35.8
5 yr.	22.1	45.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
21.96	20.68	21.77	14.79	19.04	19.96	18.58	14.45	12.30	11.00	11.31	11.32	11.37	11.15	10.61	18.26	*16.00*	*16.50*	Revenues per sh	*18.25*
2.23	2.39	2.40	2.69	3.01	3.31	3.69	3.46	3.40	3.23	3.31	3.34	3.74	4.02	4.03	4.44	*4.45*	*4.40*	"Cash Flow" per sh	*6.25*
1.23	1.32	1.25	1.33	1.50	1.73	1.79	1.94	1.98	1.69	1.69	1.92	2.12	2.24	2.08	2.36	*2.25*	*2.10*	Earnings per sh A	*3.25*
.67	.68	.70	.71	.73	.76	.80	.85	.95	1.05	1.16	1.27	1.40	1.51	1.58	1.63	*1.64*	*1.70*	Div'd Decl'd per sh B ■	*1.85*
2.67	3.04	4.01	4.37	4.36	6.48	5.85	4.99	2.86	2.74	3.31	4.13	2.87	3.18	3.25	3.89	*4.75*	*4.75*	Cap'l Spending per sh	*4.75*
8.79	9.16	10.14	10.52	11.73	13.06	14.00	15.30	16.27	16.66	17.24	19.28	20.06	20.69	18.15	20.27	*21.25*	*22.25*	Book Value per sh C	*26.00*
182.40	183.60	187.00	194.00	195.20	196.20	197.60	198.50	199.40	199.70	199.70	199.70	199.70	200.10	200.10	200.10	*200.20*	*200.20*	Common Shs Outst'g D	*200.20*
13.7	13.8	12.4	10.8	13.3	14.4	15.2	17.7	18.3	17.7	17.7	18.3	16.5	19.0	16.2	14.3	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
.74	.73	.75	.72	.85	.90	.97	.99	.96	.89	.93	.92	.89	1.01	.83	.76	*Value Line*		Relative P/E Ratio	*.80*
4.0%	3.8%	4.5%	5.0%	3.7%	3.1%	2.9%	2.5%	2.6%	3.6%	3.9%	3.6%	4.0%	3.5%	4.7%	4.8%	*estimates*		Avg Ann'l Div'd Yield	*4.0%*

CAPITAL STRUCTURE as of 9/30/22
Total Debt $5279.5 mill. Due in 5 Yrs $1731.5 mill.
LT Debt $3548.0 mill. LT Interest $158.7 mill.
(LT interest earned: 4.3x)

Leases, Uncapitalized Annual rentals $5.7 mill.

Pension Assets-12/21 $486.0 mill. Oblig $502.9 mill.

Pfd Stock None

Common Stock 200,202,672 shs.

MARKET CAP: $8.0 billion (Mid Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
3671.2	2867.7	2453.1	2196.9	2259.2	2261.1	2270.3	2231.6	2122.3	3653.7	*3200*	*3300*	Revenues ($mill)	*3650*
355.0	387.6	395.8	337.6	338.2	384.3	425.5	449.6	415.9	472.5	*450*	*420*	Net Profit ($mill)	*665*
26.0%	24.9%	30.4%	29.2%	30.5%	32.5%	14.5%	7.4%	13.2%	11.5%	*12.0%*	*12.0%*	Income Tax Rate	*12.0%*
2.7%	2.6%	1.7%	3.7%	6.4%	15.0%	8.3%	1.6%	1.6%	2.2%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
50.7%	43.1%	45.9%	44.3%	41.1%	41.7%	42.0%	43.6%	49.0%	52.6%	*46.0%*	*52.0%*	Long-Term Debt Ratio	*50.0%*
49.3%	56.9%	54.1%	55.7%	58.9%	58.3%	58.0%	56.4%	51.0%	47.4%	*53.0%*	*48.0%*	Common Equity Ratio	*50.0%*
5615.8	5337.2	5999.7	5971.6	5849.6	6600.7	6902.0	7334.7	7126.2	8552.7	*8100*	*9400*	Total Capital ($mill)	*10400*
8344.8	6672.8	6979.9	7322.4	7696.2	8339.9	8643.8	9044.6	9374.6	9832.9	*10345*	*10830*	Net Plant ($mill)	*12075*
7.7%	8.6%	7.8%	6.9%	7.0%	7.0%	7.3%	7.1%	6.9%	6.4%	*7.5%*	*6.5%*	Return on Total Cap'l	*7.5%*
12.8%	12.8%	12.2%	10.2%	9.8%	10.0%	10.6%	10.9%	11.5%	11.6%	*12.0%*	*12.0%*	Return on Shr. Equity	*13.0%*
12.8%	12.8%	12.2%	10.2%	9.8%	10.0%	10.6%	10.9%	11.5%	11.6%	*12.0%*	*12.0%*	Return on Com Equity E	*13.0%*
7.2%	7.3%	6.5%	4.0%	3.3%	3.5%	3.8%	3.6%	2.8%	3.6%	*4.0%*	*4.5%*	Retained to Com Eq	*5.5%*
44%	43%	47%	61%	67%	64%	64%	67%	76%	69%	*73%*	*81%*	All Div'ds to Net Prof	*57%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	+1.1	-4.9	+2.6
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	4.69	4.40	7.68
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	6817	6437	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.0	+1.1	+1.4
Fixed Charge Cov. (%)	335	326	336

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-3.0%	3.0%	5.5%
"Cash Flow"	3.5%	4.5%	7.0%
Earnings	4.0%	4.5%	6.5%
Dividends	8.0%	8.5%	3.0%
Book Value	5.5%	3.5%	5.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	490.0	513.7	755.4	472.5	2231.6
2020	431.3	503.5	702.1	485.4	2122.3
2021	1630.6	577.4	864.4	581.3	3653.7
2022	589.3	803.7	1270.8	*536.2*	*3200*
2023	*600*	*800*	*1200*	*700*	*3300*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.24	.50	1.25	.26	2.24
2020	.23	.51	1.04	.30	2.08
2021	.26	.56	1.26	.27	2.36
2022	.33	.36	1.31	*.25*	*2.25*
2023	*.32*	*.33*	*1.25*	*.20*	*2.10*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.3325	.3325	.3325	.365	1.36
2019	.365	.365	.365	.388	1.48
2020	.3875	.3875	.3875	.4025	1.57
2021	.4025	.4025	.4025	.41	1.62
2022	.41	.41	.41	.4141	

BUSINESS: OGE Energy Corp. is a holding company for Oklahoma Gas and Electric Company (OG&E), which supplies electricity to 879,000 customers in Oklahoma (84% of electric revenues) and western Arkansas (8%); wholesale is (8%). Owns 3% of Energy Transfer's limited partnership units. Electric revenue breakdown: residential, 44%; commercial, 25%; industrial, 11%; oilfield, 10%; other, 10%. Generating sources: gas, 25%; coal, 21%; wind, 6%; purchased, 48%. Fuel costs: 58% of revenues. '21 reported depreciation rate (utility): 2.6%. Has 2,200 employees. Chairman, President and Chief Executive Officer: Sean Trauschke. Incorporated: Oklahoma. Address: 321 North Harvey, P.O. Box 321, Oklahoma City, OK 73101-0321. Tel.: 405-553-3000. Internet: www.oge.com.

OGE Energy's utility subsidiary in Oklahoma agreed to a $30 million settlement in its general rate case. The company initially requested a $164 million increase which was reduced drastically by the Oklahoma Corporation Commission after regulatory hearings. The commission is now considering spreading out monthly price increases of $9.72 over a three to four year time frame, compared to the current two-year span to help mitigate the impact on customer bills. In Arkansas, the utility implemented its new fuel rates which went into effect on November 1st. The increases will recover $40 million over the next 17 months.

We see earnings declining through 2023. Management continues to expect long-term share-earnings growth of 5%-7% annually, based off 2021 profits. (Excluding equity income.) For 2022, the company expects share earnings in a range of $2.08-$2.12 a share. Our full-year 2022 and 2023 bottom-line estimates are $2.25 a share (including equity income from Energy Transfer stake), and $2.10 a share, respectively. We have lowered our 2023 forecasts due to the macroeconomic climate, including margin pressures from rising interest rates, along with depreciation rates and pending rate reviews.

In the third quarter, OGE completed its transformation to an electric utility, after selling its Energy Transfer units. The exit from midstream operations should reduce business risk and attract investors as it becomes a pure-play electric utility. The natural gas midstream segment has long been a weakness, and the exit should improve performance.

These shares are ranked to mirror the broader market averages in the coming six to 12 months. Equities in the utilities industry have faced immense pressure as of late due to rising interest rates. Rising Treasury yields are becoming more appealing to income-oriented investors, challenging the attractiveness of the utility industry. As a result, the stock is down more than 5% in value since our last report in September. While total return potential is below average for the 18-month and 3- to 5-year period, these shares hold an attractive dividend yield that is well above the utility average.

Zachary J. Hodgkinson *December 9, 2022*

(A) Diluted EPS. Excl. nonrecurring gains (losses): '15, (33¢); '17, $1.18; '19, (8¢); '20, ($2.95); '21, $1.32; '22, $1.06; gain on discont. ops.: '06, 20¢. '19 & '21 EPS don't sum due to rounding. Next earnings report due late Feb. (B) Div'ds historically paid in late Jan., Apr., July, & Oct. ■ Div'd reinvestment plan avail. (C) Incl. deferred charges. In '21: $6.15/sh. (D) In mill., adj. for split. (E) Rate base: Net original cost. Rate allowed on com. eq. in OK in '19: 9.5%; in AR in '18: 9.5%; earned on avg. com. eq., '21: 12.7%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	25
Earnings Predictability	95

OTTER TAIL CORP. NDQ-OTTR

RECENT PRICE 57.42 | P/E RATIO 10.3 (Trailing: 8.2; Median: 20.0) | RELATIVE P/E RATIO 0.63 | DIV'D YLD 2.9% | VALUE LINE

TIMELINESS 2 Lowered 12/9/22

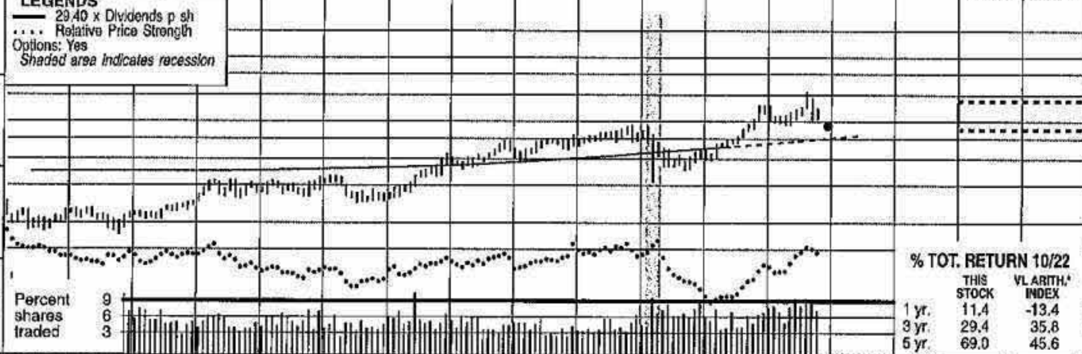
SAFETY 2 Raised 6/17/16

TECHNICAL 2 Lowered 12/9/22

BETA .85 (1.00 = Market)

High:	23.5	25.3	31.9	32.7	33.4	42.6	48.7	51.9	57.7	56.9	71.7	82.5	
Low:	17.5	20.7	25.2	26.5	24.8	25.8	35.7	39.0	45.9	31.0	39.4	52.6	

Target Price Range 2025 | 2026 | 2027



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$56-$111	$84 (45%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+30%)	10%
Low	55	(-5%)	3%

Institutional Decisions

	1Q2022	2Q2022	3Q2022
to Buy	121	121	140
to Sell	87	103	95
Hld's(000)	19574	20044	20598

% TOT. RETURN 10/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	11.4	-13.4
3 yr.	29.4	35.8
5 yr.	69.0	45.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
37.43	41.50	37.06	29.03	31.08	29.86	23.76	24.63	21.48	20.60	20.42	21.47	23.10	22.90	21.46	28.80	*35.45*	*29.35*	Revenues per sh	*32.25*
3.39	3.55	2.81	2.76	2.60	2.36	2.71	3.02	3.09	3.14	3.44	3.70	3.96	4.11	4.29	6.45	*7.75*	*6.60*	"Cash Flow" per sh	*6.75*
1.69	1.78	1.09	.71	.38	.45	1.05	1.37	1.55	1.56	1.60	1.86	2.06	2.17	2.34	4.23	*6.60*	*4.75*	Earnings per sh A	*3.75*
1.15	1.17	1.19	1.19	1.19	1.19	1.19	1.19	1.21	1.23	1.25	1.28	1.34	1.40	1.48	1.56	*1.65*	*1.76*	Div'd Decl'd per sh B ■	*2.20*
2.35	5.43	7.51	4.95	2.38	2.04	3.20	4.53	4.40	4.23	4.10	3.36	2.66	5.16	8.96	4.14	*4.35*	*5.90*	Cap'l Spending per sh	*6.25*
16.67	17.55	19.14	18.78	17.57	15.83	14.43	14.75	15.39	15.98	17.03	17.62	18.38	19.46	21.00	23.84	*27.55*	*29.80*	Book Value per sh C	*34.25*
29.52	29.85	35.38	35.81	36.00	36.10	36.17	36.27	37.22	37.86	39.35	39.56	39.66	40.16	41.47	41.55	*41.75*	*41.90*	Common Shs Outst'g D	*42.50*
17.3	19.0	30.1	31.2	NMF	NMF	21.7	21.1	18.8	18.2	20.2	22.1	22.2	23.5	18.3	12.3	*Bold figures are*		Avg Ann'l P/E Ratio	*17.5*
.93	1.01	1.81	2.08	NMF	NMF	1.38	1.19	.99	.92	1.06	1.11	1.20	1.25	.94	.66	*Value Line*		Relative P/E Ratio	*.95*
3.9%	3.5%	3.6%	5.4%	5.7%	5.6%	5.2%	4.1%	4.1%	4.3%	3.9%	3.1%	2.9%	2.7%	3.5%	3.0%	*estimates*		Avg Ann'l Div'd Yield	*3.4%*

CAPITAL STRUCTURE as of 9/30/22
Total Debt $823.8 mill. Due in 5 Yrs $207.8 mill.
LT Debt $823.8 mill. LT Interest $31.6 mill.
(LT interest earned: 9.7x)

Leases, Uncapitalized Annual rentals $5.0 mill.
Pension Assets-12/21 $387.2 mill. Oblig $416.7 mill.

Pfd Stock None

Common Stock 41,630,952 shs. as of 10/25/22

MARKET CAP: $2.4 billion (Mid Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
859.2	893.3	799.3	779.8	803.5	849.4	916.4	919.5	890.1	1196.8	*1480*	*1230*	Revenues ($mill)	*1370*
39.0	50.2	56.9	58.6	62.0	73.9	82.3	86.8	95.9	176.8	*250*	*200*	Net Profit ($mill)	*165*
5.2%	21.3%	22.5%	27.0%	24.5%	25.5%	15.0%	16.7%	17.4%	16.9%	*20.0%*	*20.0%*	Income Tax Rate	*20.0%*
1.7%	5.6%	3.9%	3.5%	2.2%	2.3%	4.1%	4.9%	6.4%	.8%	*1.0%*	*3.0%*	AFUDC % to Net Profit	*4.0%*
44.0%	42.1%	46.5%	42.4%	43.0%	41.3%	44.7%	46.9%	41.8%	42.6%	*41.5%*	*41.5%*	Long-Term Debt Ratio	*42.5%*
54.4%	57.9%	53.5%	57.6%	57.0%	58.7%	55.3%	53.1%	58.2%	57.4%	*58.5%*	*58.5%*	Common Equity Ratio	*57.5%*
959.2	924.4	1071.3	1051.0	1175.4	1187.3	1318.9	1471.1	1495.4	1724.8	*1975*	*2140*	Total Capital ($mill)	*2525*
1049.5	1167.0	1268.5	1387.8	1477.2	1539.6	1581.1	1753.8	2049.3	2124.6	*2210*	*2355*	Net Plant ($mill)	*2700*
5.7%	6.8%	6.7%	6.8%	6.5%	7.3%	7.3%	7.0%	7.4%	11.1%	*12.0%*	*9.0%*	Return on Total Cap'l	*7.5%*
7.3%	9.4%	9.9%	9.7%	9.3%	10.6%	11.3%	11.1%	11.0%	17.8%	*19.5%*	*13.5%*	Return on Shr. Equity E	*11.5%*
7.3%	9.3%	9.9%	9.7%	9.3%	10.6%	11.3%	11.1%	11.0%	17.8%	*19.5%*	*13.5%*	Return on Com Equity	*11.5%*
NMF	1.2%	2.2%	2.0%	2.1%	3.3%	4.0%	4.0%	4.1%	11.3%	*13.5%*	*7.5%*	Retained to Com Eq	*5.0%*
113%	87%	78%	79%	78%	69%	65%	64%	63%	37%	*31%*	*44%*	All Div'ds to Net Prof	*57%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-.2	-3.9	+.3
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.1	NA	NA
Fixed Charge Cov. (%)	407	405	651

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-2.0%	3.0%	*5.0%*
"Cash Flow"	7.0%	9.0%	*5.5%*
Earnings	19.0%	13.0%	*4.5%*
Dividends	2.0%	4.0%	*7.0%*
Book Value	2.0%	6.0%	*8.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	246.0	229.2	228.6	215.7	919.5
2020	234.7	192.8	235.8	226.8	890.1
2021	261.7	285.6	316.3	333.2	1196.8
2022	374.9	400.0	383.9	*321.2*	*1480*
2023	*320*	*315*	*300*	*295*	*1230*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.66	.39	.62	.51	2.17
2020	.60	.42	.87	.45	2.34
2021	.73	1.01	1.26	1.23	4.23
2022	1.72	2.05	2.01	*.82*	*6.60*
2023	*1.40*	*1.35*	*1.20*	*.80*	*4.75*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.335	.335	.335	.335	1.34
2019	.35	.35	.35	.35	1.40
2020	.37	.37	.37	.37	1.48
2021	.39	.39	.39	.39	1.56
2022	.4125	.4125	.4125	.4125	

BUSINESS: Otter Tail Corporation is the parent of Otter Tail Power Company, which supplies electricity to 133,000 customers in Minnesota (52% of retail electric revenues), North Dakota (38%), and South Dakota (10%). Electric rev. breakdown: residential, 32%; commercial & farms, 36%; industrial, 30%; other, 2%. Generating sources: coal, 38%; wind & other, 18%; purchased, 44%. Fuel costs: 10% of revenues. Also has operations in manufacturing and plastics (62% of '21 operating income). '21 deprec. rate: 2.9%. Has 2,500 employees. Chairman: Nathan I. Partain. President & CEO: Charles S. MacFarlane. Inc.: Minnesota. Address: 215 South Cascade St., P.O. Box 496, Fergus Falls, Minnesota 56538-0496. Tel.: 866-410-8780. Internet: www.ottertail.com.

Shares of Otter Tail have declined significantly in value since our September report. The stock price has dropped more than 25%, compared to a 10% decline in XLU shares (an S&P utility sector fund) over that interim. In fact, in that time span the utility turned in the worst-performance out of all the companies covered by *Value Line* in the Electric Utility (Central) Industry. Too, management is concerned about near-term prospects because of resin price reductions and the weakening home improvement market. The company lowered its 2022 share-earnings target from $6.83-$7.13 to $6.42-$6.72. The Plastics segment, which has been a main driver for earnings recently, is facing a slowdown in PVC pipe demand that will likely continue to hurt profits in the future. Sales volume decreased by 15% in the third-quarter due to the headwinds previously mentioned.

Nevertheless, the company delivered strong financial results in the third quarter. Share earnings grew about 60% year over year, while revenues increased 21% over that span. Performance was well rounded, highlighted by the Plastics segment, as mentioned, despite lower-than-expected sales volumes.

The company remains committed to its long-term annual earnings growth rate target of 5%-7%, using 2024 as the base year. While this is certainly in the cards, we expect the bottom-line to decline next year as conditions normalize within the utility's Plastics division. We are looking for 2023 full-year earnings of $4.75 a share.

Otter Tail shares are best suited for accounts with a short-to-intermediate investment horizon. The stock currently carries our Timeliness rank of 2, making it a strong selection for the next six to 12 months. Too, given the aforementioned drop in its value, the utility now offers much stronger capital appreciation potential. The midpoint of our 18-month Target Price Range represents a 45% premium to its current price. Capital appreciation potential out to 2025-2027 is not appealing as these shares remain within our 3- to 5-year estimate. This stock also offers a yield of 2.9%, which is just below-average for a utility.

Zachary J. Hodgkinson *December 9, 2022*

(A) Dil. EPS. Excl. nonrec. gains (loss): '10, (44¢); '11, 26¢; '13, 2¢; gains (losses) from disc. ops.: '06, 1¢; '11, ($1.11); '12, ($1.22); '13, 2¢; '14, 2¢; '15, 2¢; '16, 1¢; '17, 1¢. '19 EPS may not sum due to rounding. Next earnings report due early Feb. (B) Div'ds histor. pd. in early Mar., Jun., Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. intang. In '21: $4.14/sh. (D) In mill. (E) Rate all'd on com. eq. in MN in '22: 9.48%; in ND in '18: 9.77%; in SD in '19: 8.75%; earned on avg. com. eq., '21: 19.2%.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	70
Earnings Predictability	70

PORTLAND GENERAL NYSE-POR

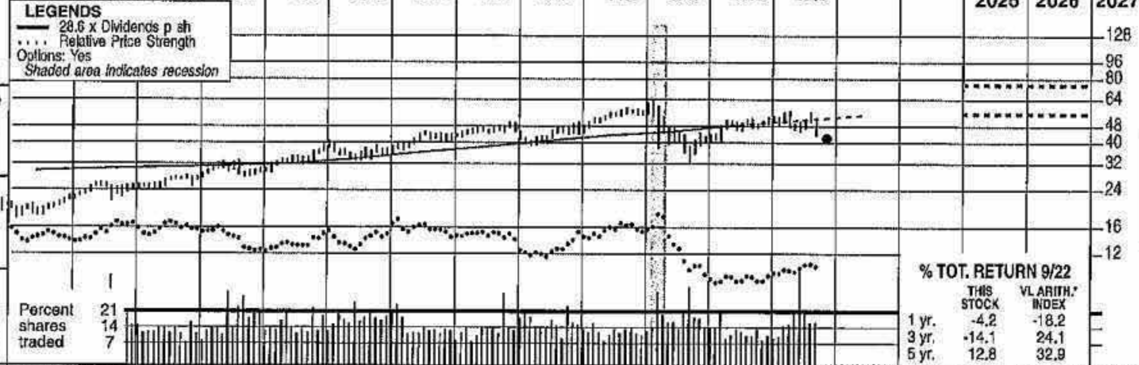
RECENT PRICE 42.17 | P/E RATIO 14.4 (Trailing: 15.7 / Median: 18.0) | RELATIVE P/E RATIO 0.98 | DIV'D YLD 4.4% | VALUE LINE

TIMELINESS 3 Raised 10/7/22
SAFETY 2 Raised 10/22/21
TECHNICAL 1 Raised 9/23/22
BETA .85 (1.00 = Market)

High:	26.0	26.1	33.3	40.3	41.0	45.2	50.1	50.4	58.4	63.1	53.1	57.0
Low:	21.3	24.3	27.4	29.0	33.0	35.3	42.4	39.0	44.0	32.0	40.8	42.0

Target Price Range 2025 | 2026 | 2027

LEGENDS
— 28.6 x Dividends p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



18-Month Target Price Range
Low-High Midpoint (% to Mid)
$44-$70 $57 (35%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+80%)	19%
Low	55	(+30%)	11%

Institutional Decisions

	4Q2021	1Q2022	2Q2022
to Buy	149	178	181
to Sell	141	142	153
Hld's(000)	81443	82974	89213

Percent shares traded 21 14 7

% TOT. RETURN 9/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-4.2	-18.2
3 yr.	-14.1	24.1
5 yr.	12.8	32.9

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB, LLC	25-27
24.32	27.87	27.89	23.99	23.67	24.06	23.89	23.18	24.29	21.38	21.62	22.54	22.30	23.75	23.96	26.80	*27.35*	*28.20*	Revenues per sh	*30.75*
4.64	5.21	4.71	4.07	4.82	4.96	5.15	4.93	6.08	5.37	5.78	6.16	6.65	6.97	7.83	7.25	*7.60*	*8.05*	"Cash Flow" per sh	*9.40*
1.14	2.33	1.39	1.31	1.66	1.95	1.87	1.77	2.18	2.04	2.16	2.29	2.37	2.39	2.75	2.72	*2.80*	*2.95*	Earnings per sh A	*3.45*
.68	.93	.97	1.01	1.04	1.06	1.08	1.10	1.12	1.18	1.26	1.34	1.43	1.52	1.59	1.70	*1.79*	*1.89*	Div'd Decl'd per sh B ■ †	*2.24*
5.94	7.28	6.12	9.25	5.97	3.98	4.01	8.40	12.87	6.73	6.57	5.77	6.67	6.78	8.76	7.11	*7.65*	*7.55*	Cap'l Spending per sh	*7.60*
19.58	21.05	21.64	20.50	21.14	22.07	22.87	23.30	24.43	25.43	26.35	27.11	28.07	28.99	29.18	30.28	*31.25*	*32.35*	Book Value per sh C	*35.80*
62.50	62.53	62.58	75.21	75.32	75.36	75.56	78.09	78.23	88.79	88.95	89.11	89.27	89.39	89.54	89.41	*89.50*	*89.50*	Common Shs Outst'g D	*89.50*
23.4	11.9	16.3	14.4	12.0	12.4	14.0	16.9	15.3	17.7	19.1	20.0	18.4	22.3	16.6	17.7	**Bold figures are**		Avg Ann'l P/E Ratio	*18.5*
1.26	.63	.98	.96	.76	.78	.89	.95	.81	.89	1.00	1.01	.99	1.19	.85	.95	*Value Line*		Relative P/E Ratio	*1.05*
2.5%	3.3%	4.3%	5.4%	5.2%	4.4%	4.1%	3.7%	3.3%	3.3%	3.1%	2.9%	3.3%	2.8%	3.5%	3.5%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*
						1805.0	1810.0	1900.0	1898.0	1923.0	2009.0	1991.0	2123.0	2145.0	2396.0	*2450*	*2525*	Revenues ($mill)	*2750*
						141.0	137.0	175.0	172.0	193.0	204.0	212.0	214.0	247.0	244.0	*250*	*265*	Net Profit ($mill)	*310*
						31.4%	23.2%	26.0%	20.7%	20.6%	25.3%	7.4%	11.2%	12.4%	8.6%	*17.5%*	*17.5%*	Income Tax Rate	*17.5%*
						7.1%	14.6%	33.7%	19.8%	16.6%	8.8%	8.0%	7.0%	9.7%	10.2%	*10.0%*	*9.0%*	AFUDC % to Net Profit	*8.0%*
						47.1%	51.3%	52.7%	47.8%	48.4%	50.1%	46.5%	51.3%	53.6%	56.8%	*55.5%*	*56.0%*	Long-Term Debt Ratio	*57.5%*
						52.9%	48.7%	47.3%	52.2%	51.6%	49.9%	53.5%	48.7%	46.4%	43.2%	*44.5%*	*44.0%*	Common Equity Ratio	*42.5%*
						3264.0	3735.0	4037.0	4329.0	4544.0	4842.0	4684.0	5323.0	5628.0	6265.0	*6315*	*6565*	Total Capital ($mill)	*7575*
						4392.0	4880.0	5679.0	6012.0	6434.0	6741.0	6887.0	7161.0	7539.0	8005.0	*8260*	*8460*	Net Plant ($mill)	*9000*
						5.9%	5.1%	5.8%	5.4%	5.6%	5.5%	5.8%	5.1%	5.6%	4.9%	*5.0%*	*5.0%*	Return on Total Cap'l	*5.0%*
						8.2%	7.5%	9.2%	7.6%	8.2%	8.4%	8.5%	8.3%	9.5%	9.0%	*9.0%*	*9.0%*	Return on Shr. Equity	*9.5%*
						8.2%	7.5%	9.2%	7.6%	8.2%	8.4%	8.5%	8.3%	9.5%	9.0%	*9.0%*	*9.0%*	Return on Com Equity E	*9.5%*
						3.5%	2.9%	4.6%	3.3%	3.5%	3.6%	3.5%	3.1%	4.1%	3.5%	*3.0%*	*3.5%*	Retained to Com Eq	*3.5%*
						57%	61%	50%	56%	57%	58%	59%	63%	57%	61%	*64%*	*64%*	All Div'ds to Net Prof	*65%*

CAPITAL STRUCTURE as of 6/30/22
Total Debt $3604 mill. Due in 5 Yrs $186 mill.
LT Debt $3583 mill. LT Interest $128 mill.
Incl. $273 mill. finance leases.
(Total interest Coverage: 2.9x)
Leases, Uncapitalized Annual rentals $4 mill.
Pension Assets-12/21 $800 mill. Oblig $972 mill.

Pfd Stock None

Common Stock 89,242,847 shs. as of 7/21/22

MARKET CAP: $3.8 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	+1.2	+.4	+5.1
Avg. Indust. Use (MWH)	17827	18472	20002
Avg. Indust. Revs. per KWH (¢)	4.75	4.99	5.22
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	3765	3771	4447
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.1	+1.5	+.6
Fixed Charge Cov. (%)	265	187	261

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	0.5%	2.0%	3.5%
"Cash Flow"	5.0%	5.0%	4.0%
Earnings	5.0%	4.5%	4.5%
Dividends	4.5%	6.0%	6.0%
Book Value	3.5%	3.0%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	573.0	460.0	542.0	548.0	2123.0
2020	573.0	469.0	547.0	556.0	2145.0
2021	609.0	537.0	642.0	608.0	2396.0
2022	626.0	591.0	*633*	*600*	*2450*
2023	*645*	*580*	*660*	*640*	*2525*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.82	.28	.61	.68	2.39
2020	.91	.43	.84	.57	2.75
2021	1.07	.36	.56	.73	2.72
2022	.67	.72	*.65*	*.76*	*2.80*
2023	*.80*	*.65*	*.70*	*.80*	*2.95*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.34	.34	.3625	.3625	1.41
2019	.3625	.3625	.385	.385	1.50
2020	.385	.385	.385	.4075	1.56
2021	.4075	.4075	.43	.43	1.68
2022	.43	.43	.4525	.4525	

BUSINESS: Portland General Electric Company (PGE) provides electricity to 917,000 customers in 51 cities in a 4,000-square-mile area of Oregon, including Portland and Salem (population: 1.9 million). The company is in the process of decommissioning the Trojan nuclear plant, which it closed in 1993. Electric revenue breakdown: residential, 47%; commercial, 29%; industrial, 11%; other, 13%. Generating sources: gas, 37%; wind, 9%; coal, 8%; hydro, 4%; purchased, 42%. Fuel costs: 34% of revenues. '21 reported depreciation rate: 3.4%. Has 2,800 full-time employees. Chairman: Jack E. Davis. President and Chief Executive Officer: Maria M. Pope. Incorporated: Oregon. Address: 121 S.W. Salmon Street, Portland, OR 97204. Tel.: 503-464-8000. Internet: www.portlandgeneral.com.

Portland General Electric (PGE) is having a good year, prompting management to lift guidance. To briefly recap, PGE received its general rate case decision from OPUC (Oregon Public Utility Commission) in late April, authorizing a 3.2% price hike. And during the first half of the year, the company profited from higher retail energy deliveries, due to continued growth in industrial demand, including high-tech and digital customers. PGE revised its 2022 GAAP-based share-earnings guidance up by a dime on both sides of the range, to $2.60-$2.75. Our estimate is higher, as we're excluding deferral reductions related to year ended 2020.

The utility is still awaiting finalized decisions on its RFP (request for proposals). PGE wants to add at least 375 to 500 megawatts of renewables and "nonemitting" capacity. In July, OPUC acknowledged PGE's submitted shortlist of bids in the pending RFP. The proposals provide various combinations of wind, solar, and battery storage options that include power purchase agreements along with company-owned resources. The goal remains for contracts to be executed with the winning bidders by year end.

PGE leadership's long-term earnings growth target of 4%-6% looks achievable. Next year will benefit from a full year of rate relief against an easy comparison. From 2023 out to mid-decade we're projecting a 5.5% growth rate in earnings. Accelerating load growth, thanks to the healthy economy of the utility's service territory, where there is a vibrant tech sector, is a key factor.

The board of directors raised the payout 5.2% this year. PGE targets a long-term growth rate of 5%-7% and a payout ratio of 60%-70%. Our projections assume a 6% rate of growth to mid-decade.

Utility investors may want to consider this issue for a long-term holding. Neutrally ranked PGE offers a healthy dividend yield that's 40 basis points above the electric utility median. This despite EPS and dividend growth rates being decently above the industry averages. Market weakness has the stock down 13% since our July report, and near the bottom of our 18-month Target Price Range, thereby offering solid recovery potential.

Anthony J. Glennon *October 21, 2022*

(A) Diluted earnings. Excl. nonrecurring gains/(losses): '13, (42¢); '17, (19¢); '20, ($1.03); '22, (14¢). Next earnings report due October 25th.
(B) Dividends paid mid-Jan., Apr., July, and Oct. ■ Dividend reinvestment plan available. † Shareholder investment plan available.
(C) Incl. deferred charges. In '21: $533 mill., $5.96/sh. (D) In mill.
(E) Rate base: Net original cost. Rate allowed on common equity in '22: 9.5%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	65
Earnings Predictability	95

SOUTHERN COMPANY NYSE-SO

RECENT PRICE	65.48	P/E RATIO	19.5 (Trailing: 17.3; Median: 17.0)	RELATIVE P/E RATIO	1.27	DIV'D YLD	4.2%	VALUE LINE

TIMELINESS 3 Lowered 11/11/22
SAFETY 2 Lowered 2/21/14
TECHNICAL 1 Raised 10/21/22
BETA .95 (1.00 = Market)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	46.7	48.6	48.7	51.3	53.2	54.6	53.5	49.4	64.3	71.1	68.9	80.6					
Low:	35.7	41.8	40.0	40.3	41.4	46.0	46.7	42.4	43.3	42.0	56.7	60.7					

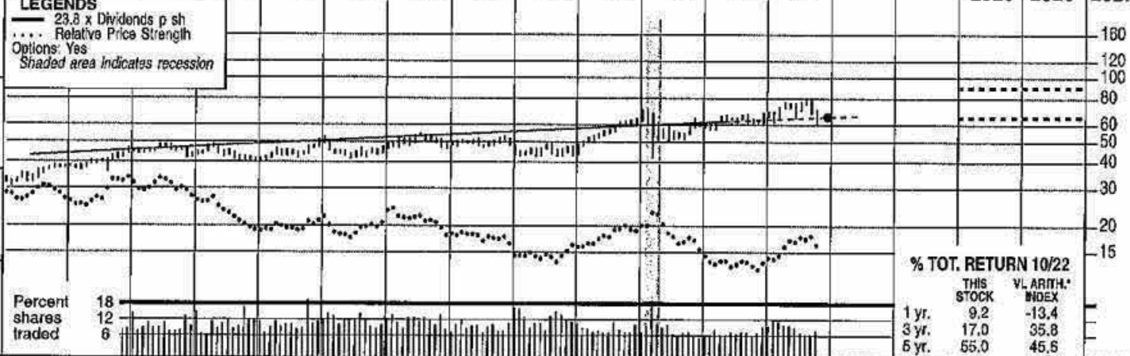
18-Month Target Price Range
Low-High Midpoint (% to Mid)
$57-$91 $74 (15%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	90	(+35%)	12%
Low	65	(Nil)	4%

Institutional Decisions

	4Q2021	1Q2022	2Q2022
to Buy	856	770	774
to Sell	553	655	650
Hld's(000)	643341	657062	662355



% TOT. RETURN 10/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	9.2	-13.4
3 yr.	17.0	35.8
5 yr.	55.0	45.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
19.24	20.12	22.04	19.21	20.70	20.41	19.06	19.26	20.34	19.18	20.09	22.86	22.73	20.34	19.29	21.80	*24.30*	*24.85*	Revenues per sh	*28.75*
4.01	4.22	4.43	4.43	4.51	4.91	5.18	5.27	5.28	5.47	5.69	6.64	6.41	6.33	6.98	7.20	*7.30*	*7.65*	"Cash Flow" per sh	*9.25*
2.10	2.28	2.25	2.32	2.36	2.55	2.67	2.70	2.77	2.84	2.83	3.21	3.00	3.17	3.25	3.42	*3.55*	*3.70*	Earnings per sh A	*4.75*
1.54	1.60	1.66	1.73	1.80	1.87	1.94	2.01	2.08	2.15	2.22	2.30	2.38	2.46	2.54	2.62	*2.70*	*2.78*	Div'd Decl'd per sh B ■	*3.10*
4.01	4.65	5.10	5.70	4.85	5.23	5.54	6.16	6.58	6.22	7.38	7.37	7.74	7.17	7.04	6.83	*7.55*	*7.85*	Cap'l Spending per sh	*7.50*
15.24	16.23	17.08	18.15	19.21	20.32	21.09	21.43	21.98	22.59	25.00	23.98	23.92	26.11	26.48	26.30	*27.05*	*28.00*	Book Value per sh C	*32.25*
746.27	763.10	777.19	819.65	843.34	865.13	867.77	887.09	907.78	911.72	990.39	1007.6	1033.8	1053.3	1056.5	1060.0	*1070.0*	*1070.0*	Common Shs Outst'g D	*1070.0*
16.2	16.0	16.1	13.5	14.9	15.8	17.0	16.2	16.0	15.8	17.8	15.5	15.1	17.6	17.9	18.4	**Bold figures are**		Avg Ann'l P/E Ratio	*16.5*
.87	.85	.97	.90	.95	.99	1.08	.91	.84	.80	.93	.78	.82	.94	.92	1.00	*Value Line*		Relative P/E Ratio	*.90*
4.5%	4.4%	4.8%	5.5%	5.1%	4.6%	4.3%	4.6%	4.7%	4.8%	4.4%	4.6%	5.3%	4.4%	4.4%	4.2%	*estimates*		Avg Ann'l Div'd Yield	*4.0%*

CAPITAL STRUCTURE as of 9/30/22
Total Debt $55066 mill. Due in 5 Yrs $15427 mill.
LT Debt $50427 mill. LT Interest $1754 mill.
Incl. $215 mill. finance leases.
(LT interest earned: 3.3x)
Leases, Uncapitalized Annual rentals $307 mill.
Pension Assets-12/21 $17225 mill.
Oblig $16382 mill.
Pfd Stock $242 mill. Pfd Div'd $15 mill.
Incl. 10 mill. shs. 5.83% cum. pfd. ($25 stated value); 475,115 shs. 4.2%-5.44% cum. pfd. ($100 par).
Common Stock 1,088,672,828 shs.
MARKET CAP: $71.3 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
16537	17087	18467	17489	19896	23031	23495	21419	20375	23113	*26000*	*26600*	Revenues ($mill)	*30850*
2415.0	2439.0	2567.0	2647.0	2757.0	3269.0	3096.0	3354.0	3481.0	3670.0	*3695*	*3875*	Net Profit ($mill)	*4980*
35.6%	34.8%	33.8%	33.4%	28.5%	25.2%	21.3%	15.9%	14.3%	16.3%	*15.0%*	*15.0%*	Income Tax Rate	*15.0%*
9.4%	11.6%	13.9%	13.2%	11.9%	7.6%	6.8%	6.0%	6.6%	7.7%	*8.0%*	*8.0%*	AFUDC % to Net Profit	*6.0%*
49.9%	51.5%	49.5%	52.8%	61.5%	64.5%	62.0%	60.1%	61.5%	64.0%	*63.5%*	*64.0%*	Long-Term Debt Ratio	*63.0%*
47.3%	45.8%	47.3%	44.0%	35.7%	35.0%	37.6%	39.5%	38.1%	35.6%	*36.0%*	*36.0%*	Common Equity Ratio	*37.0%*
38653	41483	42142	46788	69359	68953	65750	69594	73336	78285	*80550*	*83500*	Total Capital ($mill)	*93500*
48390	51208	54868	61114	78446	79872	80797	83080	87634	91108	*95150*	*99350*	Net Plant ($mill)	*110000*
7.3%	6.8%	7.1%	6.6%	4.9%	5.9%	5.9%	6.0%	5.9%	5.8%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.5%*
12.5%	12.1%	12.1%	12.0%	10.3%	13.3%	12.4%	12.1%	12.3%	13.0%	*12.5%*	*13.0%*	Return on Shr. Equity	*14.5%*
12.8%	12.5%	12.5%	12.6%	11.0%	13.4%	12.5%	12.1%	12.4%	13.1%	*13.0%*	*13.0%*	Return on Com Equity E	*14.5%*
3.6%	3.2%	3.2%	3.1%	2.5%	3.9%	2.6%	2.8%	2.8%	3.1%	*3.0%*	*3.5%*	Retained to Com Eq	*5.0%*
73%	75%	75%	76%	78%	72%	79%	77%	78%	76%	*78%*	*77%*	All Div'ds to Net Prof	*67%*

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-8.5	-5.3	+2.0
Avg. Indust. Use (MWH)	2947	NA	NA
Avg. Indust. Revs. per KWH (¢)	6.03	NA	NA
Capacity at Yearend (Mw)	41940	NA	NA
Peak Load, Summer (Mw)	34209	NA	NA
Annual Load Factor (%)	60.3	NA	NA
% Change Customers (yr-end)	-8.9	+1.3	+1.5
Fixed Charge Cov. (%)	281	270	275

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	--	.5%	*6.0%*
"Cash Flow"	4.0%	4.5%	*5.0%*
Earnings	3.0%	3.0%	*6.5%*
Dividends	3.5%	3.5%	*3.5%*
Book Value	3.0%	2.5%	*3.5%*

QUARTERLY REVENUES (mill.)

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	5412	5098	5995	4914	21419
2020	5018	4620	5620	5117	20375
2021	5910	5198	6238	5767	23113
2022	6648	7206	8378	*3768*	*26000*
2023	*6700*	*6700*	*7000*	*6200*	*26600*

EARNINGS PER SHARE A

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.75	.85	1.25	.32	3.17
2020	.81	.75	1.18	.51	3.25
2021	1.09	.67	1.22	.44	3.42
2022	.97	1.07	1.31	*.20*	*3.55*
2023	*1.00*	*.85*	*1.35*	*.50*	*3.70*

QUARTERLY DIVIDENDS PAID B ■

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.58	.60	.60	.60	2.38
2019	.60	.62	.62	.62	2.46
2020	.62	.64	.64	.64	2.54
2021	.64	.66	.66	.66	2.62
2022	.66	.68	.68		

BUSINESS: The Southern Company, through its subsidiaries, supplies electricity to 4.4 mill. customers in GA, AL, and MS. Also has a competitive generation business. Acq'd AGL Resources (renamed Southern Company Gas, 4.4 mill. customers in GA, NJ, IL, VA, & TN) 7/16. Sold Gulf Power 1/19. Electric revenue breakdown: residential, 37%; commercial, 30%; industrial, 19%; other, 14%. Generating sources: gas, 44%; coal, 20%; nuclear, 16%; other, 11%; purchased, 9%. Fuel costs: 29% of revenues. '21 reported deprec. rates (utility): 2.7%-3.6%. Has 27,300 employees. Chairman, President and CEO: Thomas A. Fanning. Inc.: Delaware. Address: 30 Ivan Allen Jr. Blvd., N.W., Atlanta, Georgia 30308. Tel.: 404-506-0747. Internet: www.southerncompany.com.

Shares of Southern Company have declined significantly in value since our August report, along with many of its peers in the utilities industry. Although utility stocks have far outperformed the broader market averages this year, due to rising interest rates, it has been the worst-performing sector of the S&P 500 over the past month. However, Southern shares are outpacing their peers, as the company is up 5.5%, while the S&P Utility index is down nearly 2% this past year.

The company delivered solid financial results in the fiscal third quarter (ended September 30th). Southern posted earnings of $1.31 a share, a penny better than our estimate. Management expects adjusted full-year earnings to reach the high end of its range of $3.50 to $3.60, due to its solid first-half performance. Higher retail pricing and increased usage of utilities were the main drivers in the period. Retail sales grew 1.8% year over year and Southern Company added 11,000 electric and 8,000 gas customers in the quarter. Through the first three quarters of 2022, job additions increased 170% and business investments grew 237% compared to 2021 levels.

The utility is making progress on adding units 3 and 4 at the site of the Vogtle station. Management expects unit 3 to be placed into service by the end of the first quarter of 2023, and unit 4 is estimated by the end of next year. The project will greatly help the transition towards cleaner, more reliable energy and being carbon-free, as well as provide dividend and earnings growth moving forward. Construction timing will greatly influence growth and project delays could cause future full-year estimates to be lowered.

These shares are ranked to mirror the broader market averages in the coming six to 12 months. The stock's Timeliness rank was lowered one notch to 3 (Average). Capital-appreciation potential over the next 18 months and 3 to 5 years does not stand out compared to the industry median. On the other hand, the shares hold an Above Average (2) Safety rank, and the dividend yield of 4.2% is above the utility average of about 3.7%.

Zachary J. Hodgkinson November 11, 2022

(A) Diluted EPS. Excl. nonrec. gain (losses): '09, (25¢); '13, (83¢); '14, (59¢); '15, (25¢); '16, (28¢); '17, ($2.37); '18, (78¢); '19, $1.30; '20, (17¢); '21, (54¢). Next earnings report due in mid-Feb. (B) Div'ds paid in early Mar., June, Sept., and Dec. ■ Div'd reinvestment plan avail. (C) Incl. def'd charges. In '21: $19.83/sh. (D) In mill. (E) Rate base: AL, MS, fair value; FL, GA, orig. cost. Allowed return on common eq. (blended): 12.5%; earned on avg. com. eq., '21: 12.8%. Regulatory Climate: GA, AL Above Average; MS, FL Average.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	45
Earnings Predictability	95

XCEL ENERGY NDQ-XEL

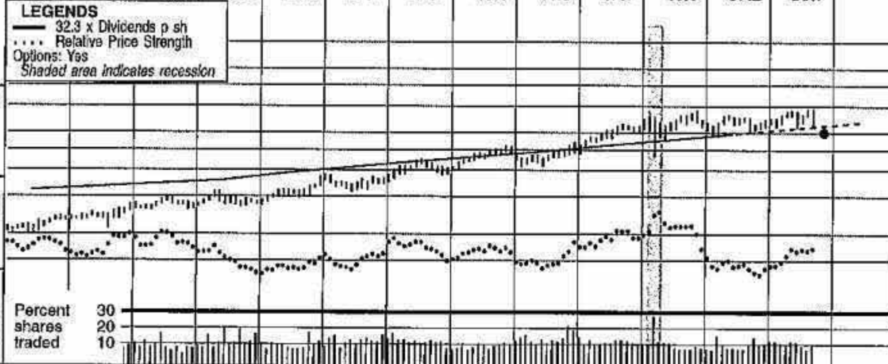
RECENT PRICE **60.21** | P/E RATIO **18.8** (Trailing: 20.0; Median: 19.0) | RELATIVE P/E RATIO **1.28** | DIV'D YLD **3.4%** | VALUE LINE

TIMELINESS **3** Raised 12/31/21
SAFETY **1** Raised 5/1/15
TECHNICAL **1** Raised 10/21/22
BETA .80 (1.00 = Market)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	27.8	29.9	31.8	37.6	38.3	45.4	52.2	54.1	66.1	76.4	72.9	77.7
Low:	21.2	25.8	26.8	27.3	31.8	35.2	40.0	41.5	47.7	46.6	57.2	59.7

Target Price Range 2025 | 2026 | 2027

LEGENDS
— 32.3 x Dividends p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



18-Month Target Price Range

Low-High Midpoint (% to Mid)
$64-$99 $82 (35%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	90	(+50%)	13%
Low	75	(+25%)	9%

Institutional Decisions

	4Q2021	1Q2022	2Q2022
to Buy	449	458	453
to Sell	338	340	368
Hld's(000)	413762	418018	424573

Percent shares traded 30 20 10

% TOT. RETURN 9/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	5.3	-18.2
3 yr.	7.0	24.1
5 yr.	55.9	32.9

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
24.16	23.40	24.69	21.08	21.38	21.90	20.76	21.92	23.11	21.72	21.90	22.46	22.44	21.98	21.45	24.69	25.90	26.35	Revenues per sh	28.50
3.61	3.45	3.50	3.48	3.51	3.79	4.00	4.10	4.28	4.56	5.04	5.47	5.92	6.25	6.61	7.08	7.75	8.30	"Cash Flow" per sh	10.00
1.35	1.35	1.46	1.49	1.56	1.72	1.85	1.91	2.03	2.10	2.21	2.30	2.47	2.64	2.79	2.96	3.15	3.35	Earnings per sh A	4.00
.88	.91	.94	.97	1.00	1.03	1.07	1.11	1.20	1.28	1.36	1.44	1.52	1.62	1.72	1.83	1.95	2.08	Div'd Decl'd per sh B ■ †	2.50
4.00	4.89	4.66	3.91	4.60	4.53	5.27	6.82	6.33	7.26	6.42	6.54	7.70	8.05	9.99	7.80	9.65	9.00	Cap'l Spending per sh	9.00
14.28	14.70	15.35	15.92	16.76	17.44	18.19	19.21	20.20	20.89	21.73	22.56	23.78	25.24	27.12	28.70	30.15	31.65	Book Value per sh C	37.00
407.30	428.78	453.79	457.51	482.33	486.49	487.96	497.97	505.73	507.54	507.22	507.76	514.04	524.54	537.44	544.03	547.00	550.00	Common Shs Outst'g D	561.00
14.8	16.7	13.7	12.7	14.1	14.2	14.8	15.0	15.4	16.5	18.5	20.2	18.9	22.3	23.9	22.5	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	20.0
.80	.89	.82	.85	.90	.89	.94	.84	.81	.83	.97	1.02	1.02	1.19	1.23	1.23	*estimates*		Relative P/E Ratio	1.10
4.4%	4.0%	4.7%	5.1%	4.5%	4.2%	3.9%	3.9%	3.8%	3.7%	3.3%	3.1%	3.3%	2.7%	2.6%	2.8%			Avg Ann'l Div'd Yield	3.1%

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
10128	10915	11686	11024	11107	11404	11537	11529	11526	13431	14175	14500	Revenues ($mill)	16000
905.2	948.2	1021.3	1063.6	1123.4	1171.0	1261.0	1372.0	1473.0	1597.0	1720	1855	Net Profit ($mill)	2260
33.2%	33.8%	33.9%	35.8%	34.1%	30.7%	12.6%	8.5%	8.5%	- -	NMF	NMF	Income Tax Rate	NMF
10.8%	13.4%	12.5%	7.7%	7.8%	9.4%	12.4%	8.3%	10.7%	6.2%	7.0%	6.0%	AFUDC % to Net Profit	5.0%
53.3%	53.3%	53.0%	54.1%	56.3%	55.9%	56.4%	56.8%	57.4%	58.2%	58.0%	58.0%	Long-Term Debt Ratio	58.0%
46.7%	46.7%	47.0%	45.9%	43.7%	44.1%	43.6%	43.2%	42.6%	41.8%	42.0%	42.0%	Common Equity Ratio	42.0%
19018	20477	21714	23092	25216	25975	28025	30646	34220	37391	39150	41600	Total Capital ($mill)	49200
23809	26122	28757	31206	32842	34329	36944	39483	42950	45457	48225	50475	Net Plant ($mill)	57000
6.1%	6.0%	6.0%	5.8%	5.7%	5.8%	5.7%	5.6%	5.4%	5.3%	5.5%	5.5%	Return on Total Cap'l	5.5%
10.2%	9.9%	10.0%	10.0%	10.2%	10.2%	10.3%	10.4%	10.1%	10.2%	10.5%	10.5%	Return on Shr. Equity	11.0%
10.2%	9.9%	10.0%	10.0%	10.2%	10.2%	10.3%	10.4%	10.1%	10.2%	10.5%	10.5%	Return on Com Equity E	11.0%
4.7%	4.5%	4.5%	4.3%	4.0%	3.9%	4.3%	4.4%	4.2%	4.2%	4.0%	4.0%	Retained to Com Eq	4.0%
54%	54%	55%	57%	61%	62%	58%	58%	58%	59%	62%	62%	All Div'ds to Net Prof	62%

CAPITAL STRUCTURE as of 6/30/22
Total Debt $23992 mill. **Due in 5 Yrs** $4911 mill.
LT Debt $23205 mill. **LT Interest** $809 mill.
incl. $73 mill. finance leases.
(Total Interest Coverage: 2.9x)

Leases, Uncapitalized Annual rentals $69 mill.
Pension Assets-12/21 $3670 mill.
Oblig $3718 mill.

Pfd Stock None

Common Stock 546,991,330 shs.
as of 7/21/22

MARKET CAP: $32.9 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-1.2	-2.3	+1.4
Large C & I Use (MWH)	NA	NA	NA
Large C & I Revs. per KWH (¢)	5.96	5.78	6.60
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	20146	19665	19849
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.0	NA	NA
Fixed Charge Cov. (%)	272	252	262

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	.5%	.5%	4.0%
"Cash Flow"	6.5%	7.5%	7.0%
Earnings	6.0%	6.0%	6.0%
Dividends	5.5%	6.0%	6.5%
Book Value	5.0%	5.0%	5.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	3141	2577	3013	2798	11529
2020	2811	2586	3182	2947	11526
2021	3541	3068	3467	3355	13431
2022	3751	3424	3900	3100	14175
2023	3875	3450	4000	3175	14500

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.61	.46	1.01	.56	2.64
2020	.56	.54	1.14	.54	2.79
2021	.67	.58	1.13	.58	2.96
2022	.70	.60	1.23	.62	3.15
2023	.75	.65	1.30	.65	3.35

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.36	.38	.38	.38	1.50
2019	.38	.405	.405	.405	1.60
2020	.405	.43	.43	.43	1.70
2021	.43	.4575	.4575	.4575	1.80
2022	.4575	.4875	.4875	.4875	

BUSINESS: Xcel Energy Inc. is the parent of Northern States Power Company (NSP), which supplies electricity to MN, WI, ND, SD & MI & gas to MN, WI, ND & MI; Public Service Company of Colorado (PSCo), which supplies electricity & gas to CO; & Southwestern Public Service Company (SPS), which supplies electricity to TX and NM. Customers: 3.7 mill. electric, 2.1 mill. gas. Electric revenue breakdown: residential, 31%; small comm'l & ind'l, 36%; large comm'l & ind'l, 18%; other, 15%. Generating sources not available. Fuel costs: 43% of revenues. '21 reported depreo. rate: 3.5%. Has 11,300 employees. Chrmn: Ben Fowke. Pres. & CEO: Bob Frenzel. Inc.: MN. Address: 414 Nicollet Mall, Minneapolis, MN 55401. Tel.: 612-330-5500. Internet: www.xcelenergy.com.

At Xcel Energy, rate relief should continue to drive steady earnings gains. Upcoming price hikes will be largely due to the approval of renewable-energy projects inclusion in the rate base, for which regulated utilities are allowed to earn a specified return on equity (ROE). The company is also effectively controlling costs despite inflationary headwinds. Our 2022 earnings estimate remains at the midpoint of Xcel's reaffirmed guidance of $3.10-$3.20 per share, given that first-half results were in line with expectations. (Entering this year our first-half share-net estimate tally was $1.33; Xcel earned $1.30 per share.) Meanwhile, our projections for 6%-6.5% profit gains in 2023 and beyond are based on the same factors. Namely, growing the rate base at its utility subsidiaries as Xcel works with its regulatory commissions to bring about a green-energy future. Company leadership has a stated earnings and dividend growth objective of 5%-7% and a solid track record that underscores its goal (see Annual Rates box). Notably, a consistently solid ROE has been delivered during both good and difficult economic times.

Xcel has numerous renewable-energy proposals up for review. The Colorado commission approved Xcel's resource plan, which includes about 4,000 megawatts (mw) of renewable (e.g., wind and solar) additions and the conversion of a major plant from coal to natural gas. This is in addition to the approved Minnesota plan, which adds 6,000 mw of renewables. RFPs (request for proposals) are being filed and commission decisions on the finer details are expected in the second half of next year. In the electric-vehicle (EV) arena, Xcel is making progress on its goal to power 1.5 million EVs by 2030. It filed transportation plans in Minnesota and Wisconsin in the third quarter. The company is looking to accelerate EV adoption through the development of high-speed public charging infrastructure in partnership with its states.

This high-quality issue offers utility investors solid risk-adjusted 3- to 5-year total returns. Its valuation is down 14% since our July report. The stock has significant recovery potential to the midpoint of our 18-month Target Price Range.

Anthony J. Glennon *October 21, 2022*

(A) Diluted EPS. Excl. nonrecurring gain (losses): '10, 5¢; '15, (16¢); '17, (5¢); gains (loss) on discontinued ops.: '06, 1¢; '09, (1¢); '10, 1¢. '20 EPS don't sum due to rounding. Next earnings report due late October. (B) Div'ds historically paid mid-Jan., Apr., July, and Oct. ■ Div'd reinvestment plan available. † Shareholder investment plan available. (C) Incl. Intangibles. In '21: $2738 mill., $4.42/sh. (D) In mill. (E) Rate base: Varies. Rate allowed on common equity (blended): 9.6%. Regulatory Climate: Average.

Company's Financial Strength	A+
Stock's Price Stability	95
Price Growth Persistence	90
Earnings Predictability	100

EXHIBIT JAC-A

Changes to FOMC Targeted Federal Funds Rate, 2006-2022

Federal Reserve Monetary Policy
Changes to FOMC Targeted Federal Funds Rate
2006 - 2022

2022

Date	Increase	Decrease	Level (%)
15-Dec	50	0	4.25-4.55
3-Nov	75	0	3.75-4.00
22-Sep	75	0	3.00-3.25
28-Jul	75	0	2.25-2.50
16-Jun	75	0	1.50-1.75
5-May	50	0	0.75-1.00
17-Mar	25	0	0.25-0.50

2020

Date	Increase	Decrease	Level (%)
16-Mar	0	100	0-0.25
3-Mar	0	50	1.00-1.25

2019

Date	Increase	Decrease	Level (%)
30-Oct	0	25	1.50-1.75
19-Sep	0	25	1.75-2.00
1-Aug	0	25	2.00-2.25

2018

Date	Increase	Decrease	Level (%)
20-Dec	25	0	2.25-2.50
27-Sep	25	0	2.00-2.25
14-Jun	25	0	1.75-2.00
22-Mar	25	0	1.50-1.75

2017

Date	Increase	Decrease	Level (%)
14-Dec	25	0	1.25-1.50
15-Jun	25	0	1.00-1.25
16-Mar	25	0	0.75-1.00

2016

Date	Increase	Decrease	Level (%)
15-Dec	25	0	0.50-0.75

2015

Date	Increase	Decrease	Level (%)
17-Dec	25	0	0.25-0.50

2008

Date	Increase	Decrease	Level (%)
16-Dec	...	75-100	0-0.25
29-Oct	...	50	1
8-Oct	...	50	1.5
30-Apr	...	25	2
18-Mar	...	75	2.25
30-Jan	...	50	3
22-Jan	...	75	3.5

2007

Date	Increase	Decrease	Level (%)
11-Dec	...	25	4.25
31-Oct	...	25	4.5
18-Sep	...	50	4.75

2006

Date	Increase	Decrease	Level (%)
29-Jun	25	...	5.25
10-May	25	...	5
28-Mar	25	...	4.75
31-Jan	25	...	4.5

Source: Federal Open Market Committee (FOMC)
Historical Archive, Target Federal Funds Rate
https://www.federalreserve.gov/monetarypolicy/openmarket.htm

EXHIBIT JAC-B

10-Year Breakeven Inflation, Measured Over 1-Month and 3-Month Periods,

January-December, Years 2021 and 2022

Tucson Electric Power Company
Test Year Ended December 31, 2021
Docket No. E-01933A-22-0107

Analysis of Changes to Market-Based 10-Year Breakeven Inflation
Measured in 1-Month and 3-Month increments over the period
January - December, 2021
(Nominal Rate - Real Rate = 10-Yr Breakeven Inflation)

10-Year Breakeven Inflation

Month	10-Year Nominal Rate	10-Year Real Rate	10-Year Breakeven Inflation
Jan-21	1.08%	-1.00%	2.08%
Feb-21	1.26%	-0.92%	2.18%
Mar-21	1.61%	-0.66%	2.28%
Apr-21	1.64%	-0.71%	2.35%
May-21	1.62%	-0.85%	2.47%
Jun-21	1.52%	-0.82%	2.34%
Jul-21	1.32%	-1.01%	2.33%
Aug-21	1.28%	-1.07%	2.35%
Sep-21	1.37%	-0.97%	2.34%
Oct-21	1.58%	-0.95%	2.54%
Nov-21	1.56%	-1.0565%	2.62%
Dec-21	1.47%	-0.9932%	2.46%

3-Month Average (January-March)	2.18%
3-Month Average (February-April)	2.27%
3-Month Average (March-May)	2.36%
3-Month Average (April-June)	2.39%
3-Month Average (May-July)	2.38%
3-Month Average (June-August)	2.34%
3-Month Average (July-September)	2.34%
3-Month Average (August-October)	2.41%
3-Month Average (September-November)	2.50%
3-Month Average (October-December)	2.54%

Source: https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield
https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=realyield

Tucson Electric Power Company
Test Year Ended December 31, 2021
Docket No. E-01933A-22-0107

Analysis of Changes to Market-Based 10-Year Breakeven Inflation
Measured in 1-Month and 3-Month increments over the period
January - December, 2022
(Nominal Rate - Real Rate = 10-Yr Breakeven Inflation)

10-Year Breakeven Inflation

Month	10-Year Nominal Rate	10-Year Real Rate	10-Year Breakeven Inflation
Nov-21	1.56%	-1.06%	2.62%
Dec-21	1.47%	-0.99%	2.46%
Jan-22	1.76%	-0.69%	2.45%
Feb-22	1.93%	-0.52%	2.46%
Mar-22	2.13%	-0.72%	2.85%
Apr-22	2.75%	-0.14%	2.88%
May-22	2.90%	0.21%	2.69%
Jun-22	3.14%	0.53%	2.62%
Jul-22	2.90%	0.53%	2.36%
Aug-22	2.90%	0.39%	2.51%
Sep-22	3.52%	1.14%	2.38%
Oct-22	3.98%	1.59%	2.39%
Nov-22	3.89%	1.52%	2.37%
Dec-22	3.62%	1.36%	**2.26%**

3-Month Average (November - January)	2.51%
3-Month Average (December-February)	2.46%
3-Month Average (January-March)	2.58%
3-Month Average (February-April)	2.73%
3-Month Average (March-May)	2.81%
3-Month Average (April-June)	2.73%
3-Month Average (May-July)	2.56%
3-Month Average (June-August)	2.50%
3-Month Average (July-September)	2.42%
3-Month Average (August-October)	2.43%
3-Month Average (September-November)	2.38%
3-Month Average (October-December)	**2.34%**

Source: https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield
https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=realyield

SCHEDULES

Tucson Electric Power Company
Test Year Ended December 31, 2021
Docket No. E-01933A-22-0107

RUCO PROPOSED
CAPITAL STRUCTURE & WEIGHTED AVERAGE COST OF CAPITAL
(Thousands of Dollars)

Line No	Description	[A] Company Proposed End of Test Year Capital Structure	[B] RUCO Adjustments	[C] RUCO Adjusted Capital Structure	[D] Capital Ratio	[E] Cost Rate	[F] Weighted Cost
1	Short-Term Debt	$ 15,000	$ (15,000)	$ -	0.00%	1.10%	0.00%
2	Long-Term Debt	$ 2,128,386	$ -	$ 2,128,386	45.68%	3.82%	1.75%
3	Common Equity	$ 2,531,209	$ -	$ 2,531,209	54.32%	9.20%	5.00%
4	TOTAL CAPITALIZATION	$ 4,674,595	$ (15,000)	$ 4,659,595	100.00%		**6.74%**

[A] : Company Schedule D-1 (Page 1 of 2) - Adjusted End of Test Year Capital Structure
[B] : [C] - [A]
[C] : Company Schedule D-1 (Page1 of 2) - Company Proposed End of Test Period Capital Structure
[D] : Capital ratio based on values shown in Column [C].
[E] : Company Schedule D-2 (Page 1 of 2); and RUCO Schedule JAC-2.
[F] : [D] * [E]

Tucson Electric Power Company
Test Year Ended December 31, 2021
Docket No. E-01933A-22-0107

Tucson Electric Power Company
Cost of Capital Calculation
Fair Value Rate Base (FVRB),
Fair Value Rate of Return (FVROR) and
Cost Rate to be Assigned to the Fair Value Increment
RUCO Recommended
($ in thousands)

Calculation of RUCO Fair Value Rate Base (FVRB)

Line No.	Rate Base Estimate		Amount	Weighting		Weighted Amount
1	[1] Original Cost Rate Base (OCRB) - RUCO Recommended	$	3,502,489	50%	$	1,751,244
2	[2] RUCO Reconstruction Cost New (RCND) Rate Base	$	6,642,627	50%		3,321,314
3	**Fair Value Rate Base (FVRB)**				**$**	**5,072,558**
4						
5	Appreciation above OCRB				$	1,570,069
6	FV/OCRB Multiple		1.45			

Calculation of RUCO Fair Value Rate of Return (FVROR)

Line No.	Capital		Amount	Percent	Cost Rate	Weighted Cost
7	Short-Term Debt	$	-	0.00%	1.10%	0.00000%
8	Long-Term Debt		1,599,849	31.54%	3.82%	1.20514%
9	Common Equity		1,902,640	37.51%	9.20%	3.45170%
10	Capital Financing OCRB	$	3,502,489			
11						
12	[3] Fair Value Increment	$	1,570,069	30.95%	0.00%	0.00%
13						
14	**Fair Value Rate of Return**	$	5,072,558	100.00%		**4.66%**

Sources:

[1] Michlik Direct, Schedule - JMM-1

[2] Michlik Direct, Schedule - JMM-1

[3] RUCO recommends a 0.00% Fair Value Increment (FVI) cost rate.

Cost of Common Equity -- RUCO Recommended

Line No.	Model	Cost of Equity
1	CAPM (at Proxy Debt Ratio)	9.51%
2	Hamada CAPM (at Company-Proposed Debt Ratio)	8.88%
3	DCF Model (Analyst Growth)	9.21%
4	**Cost of Equity (Average)**	**9.20%**
5	**Range**	**8.88% - 9.51%**

Line 1: Schedule JAC-4 (Page 4) Hamada Risk Adjustment
Line 2: Schedule JAC-4 (Page 4) Hamada Risk Adjustment
Line 3: Schedule JAC-3 (Page 2) Constant Growth DCF Results
Line 4: Arithmetic Mean of Lines [1] - [3]
Line 5: High and Low estimates, Lines [1] - [3]

Proxy Group Summary

Line No.	Proxy Company	Ticker	Market Cap. ($millions)	Market Category	Value Line Safety Rank	Financial Strength
1	ALLETE, Inc.	ALE	3,800	Mid Cap	2	A
2	Alliant Energy Corp.	LNT	14,000	Large Cap	2	A
3	Ameren Corporation	AEE	23,000	Large Cap	1	A
4	American Electric Power	AEP	48,900	Large Cap	1	A+
5	Duke Energy Corp.	DUK	84,600	Large Cap	2	A
6	Entergy Corp.	ETR	23,000	Large Cap	2	B++
7	Evergy, Inc.	EVRG	13,500	Large Cap	2	B++
8	IDACORP, Inc.	IDA	4,900	Mid Cap	1	A+
9	NextEra Energy, Inc.	NEE	152,300	Large Cap	1	A+
10	NorthWestern Corporation	NWE	2,800	Mid Cap	2	B++
11	OGE Energy Corp.	OGE	8,000	Mid Cap	2	A
12	Otter Tail Corporation	OTTR	2,400	Mid Cap	2	A
13	Portland General Electric Co.	POR	3,800	Mid Cap	2	B++
14	Southern Company	SO	71,300	Large Cap	2	A
15	Xcel Energy, Inc.	XEL	32,900	Large Cap	1	A+

Source:
Value Line Investment Survey (assorted dates: October 21, 2022; November 11, 2022; and December 9, 2022).

Note: Ms. Bulkley employs the above 15 Company Proxy Group, and RUCO does the same for purposes of its analysis.

RUCO PROXY GROUP -- CURRENT DIVIDEND YIELD

Line No	Proxy Group Companies	Ticker	(A) Indicated DPS	(B) September 2022 - November 2022 High	(C) Low	(D) Average	(E) Yield
1	ALLETE, Inc.	ALE	$2.60	$67.36	$47.77	$57.57	4.52%
2	Alliant Energy Corp.	LNT	$1.71	$63.60	$47.19	$55.40	3.09%
3	Ameren Corporation	AEE	$2.36	$96.36	$73.28	$84.82	2.78%
4	American Electric Power	AEP	$3.32	$105.60	$80.30	$92.95	3.57%
5	Duke Energy Corp.	DUK	$4.02	$111.26	$83.76	$97.51	4.12%
6	Entergy Corp.	ETR	$4.28	$122.11	$94.94	$108.53	3.94%
7	Evergy, Inc.	EVRG	$2.45	$71.13	$54.12	$62.63	3.91%
8	IDACORP, Inc.	IDA	$3.00	$112.20	$93.53	$102.87	2.92%
9	NextEra Energy, Inc.	NEE	$1.70	$91.06	$69.81	$80.44	2.11%
10	NorthWestern Corporation	NWE	$2.52	$58.50	$48.68	$53.59	4.70%
11	OGE Energy Corp.	OGE	$1.66	$42.28	$33.28	$37.78	4.38%
12	Otter Tail Corporation	OTTR	$1.65	$77.46	$52.60	$65.03	2.54%
13	Portland General Electric Co.	POR	$1.81	$53.12	$41.58	$47.35	3.82%
14	Southern Company	SO	$2.72	$80.32	$60.71	$70.52	3.86%
15	Xcel Energy, Inc.	XEL	$1.95	$77.66	$56.89	$67.28	2.90%
16	Sample Average						**3.54%**

References:

Column (A) - Value Line Investment Survey (assorted dates: October 21, 2022; November 11, 2022; and December 9, 2022).
(Reflects annualization of most recent quarterly dividend)

Columns (B), (C), and (D) - Yahoo Finance

http://finance.yahoo.com

RUCO -- DCF ANALYSIS

Line No	Proxy Group Companies	Ticker	(A) Current Dividend Yield (D_0 / P_0)	(B) 5-Yr Compound Annual Dividend per Share Growth Historic (2017-2021)	(C) 5-Yr Compound Annual Dividend per Share Growth Projected (2022-2026)	(D) Average DPS Growth	(E) Expected Dividend Yield (D_1 / P_0)	(F) DCF Rates
1	ALLETE, Inc.	ALE	4.5%	4.0%	3.5%	3.8%	4.60%	8.4%
2	Alliant Energy Corp.	LNT	3.1%	6.5%	6.0%	6.3%	3.18%	9.4%
3	Ameren Corporation	AEE	2.8%	4.0%	7.0%	5.5%	2.86%	8.4%
4	American Electric Power	AEP	3.6%	6.0%	6.0%	6.0%	3.68%	9.7%
5	Duke Energy Corp.	DUK	4.1%	3.5%	2.0%	2.8%	4.18%	6.9%
6	Entergy Corp.	ETR	3.9%	2.0%	5.0%	3.5%	4.01%	7.5%
7	Evergy, Inc.	EVRG	3.9%	N/A	7.0%	7.0%	4.05%	11.0%
8	IDACORP, Inc.	IDA	2.9%	7.0%	6.5%	6.8%	3.01%	9.8%
9	NextEra Energy, Inc.	NEE	2.1%	12.0%	10.0%	11.0%	2.23%	13.2%
10	NorthWestern Corporation	NWE	4.7%	5.5%	2.0%	3.8%	4.79%	8.5%
11	OGE Energy Corp.	OGE	4.4%	8.5%	3.0%	5.8%	4.51%	10.3%
12	Otter Tail Corporation	OTTR	2.5%	4.0%	7.0%	5.5%	2.61%	8.1%
13	Portland General Electric Co.	POR	3.8%	6.0%	6.0%	6.0%	3.94%	9.9%
14	Southern Company	SO	3.9%	3.5%	3.5%	3.5%	3.92%	7.4%
15	Xcel Energy, Inc.	XEL	2.9%	6.0%	6.5%	6.3%	2.99%	9.2%
16	Mean		3.54%	5.61%	5.40%	5.55%	3.64%	**9.19%**
17	Median		3.82%	5.75%	6.00%	5.75%	3.92%	**9.24%**
18	Average of Mean and Median							**9.21%**

References:
Column [A] : Schedule JAC - 3, Page 1.
Column [B] : Value Line Investment Survey (assorted dates: October 21, 2022; November 11, 2022; and December 9, 2022).
Column [C] : Value Line Investment Survey (assorted dates: October 21, 2022; November 11, 2022; and December 9, 2022).
Column [D] : ([B] + [C]) / 2.
Column [E] : Column [A] * (1 + (Column [D]* (0.5)))
Column [F] : [D] + [E]

CAPITAL ASSET PRICING MODEL
RUCO PROXY GROUP -- CAPM EQUITY COST RATES

Line No	Proxy Group Companies	Ticker	[A] Risk Free Rate	[B] BETA	[C] Risk Premium	[D] Beta X Risk Premium	[E] CAPM Rates
1	ALLETE, Inc.	ALE	3.98%	0.90	6.33%	5.70%	9.68%
2	Alliant Energy Corp.	LNT	3.98%	0.85	6.33%	5.38%	9.37%
3	Ameren Corporation	AEE	3.98%	0.85	6.33%	5.38%	9.37%
4	American Electric Power	AEP	3.98%	0.75	6.33%	4.75%	8.73%
5	Duke Energy Corp.	DUK	3.98%	0.85	6.33%	5.38%	9.37%
6	Entergy Corp.	ETR	3.98%	0.95	6.33%	6.01%	10.00%
7	Evergy, Inc.	EVRG	3.98%	0.90	6.33%	5.70%	9.68%
8	IDACORP, Inc.	IDA	3.98%	0.80	6.33%	5.06%	9.05%
9	NextEra Energy, Inc.	NEE	3.98%	0.90	6.33%	5.70%	9.68%
10	NorthWestern Corporation	NWE	3.98%	0.90	6.33%	5.70%	9.68%
11	OGE Energy Corp.	OGE	3.98%	1.00	6.33%	6.33%	10.32%
12	Otter Tail Corporation	OTTR	3.98%	0.85	6.33%	5.38%	9.37%
13	Portland General Electric Co.	POR	3.98%	0.85	6.33%	5.38%	9.37%
14	Southern Company	SO	3.98%	0.95	6.33%	6.01%	10.00%
15	Xcel Energy, Inc.	XEL	3.98%	0.80	6.33%	5.06%	9.05%
16	Mean			0.87			9.51%
17	Median						9.37%
18	Average of Mean and Median						9.44%

Computation of RUCO Risk Free (R_F) Rate

Line No	Month and Year	20-Year Treasury Yield	30-Year Treasury Yield	Average Long-Term Treasury Yield
19	September, 2022	3.82%	3.56%	3.69%
20	October, 2022	4.28%	4.04%	4.16%
21	November, 2022	4.22%	4.00%	4.11%
22	3-Month Average	4.10%	3.87%	3.98%
23	**RUCO Risk-Free Rate**			**3.98%**

REFERENCES

Column [A]: United States Treasury Department - Attachment 2
https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yieldYear&year=2022
Column [B]: Value Line Investment Survey (assorted dates: October 21, 2022; November 11, 2022; and December 9, 2022) - See Attachment 1
Column [C]: JAC - 4 (Page 3 of 3)
Column [D]: [B] * [C]
Column [E]: [A] + [D]

STANDARD & POOR'S 500 COMPOSITE
20-YEAR U.S. TREASURY BOND YIELDS
RISK PREMIUMS

Line No.	Year	[A] EPS	[B] BVPS	[C] ROE	[D] 20-YEAR T-BOND	[E] RISK PREMIUM
1	1977		$79.07			
2	1978	$12.33	$85.35	15.00%	7.90%	7.10%
3	1979	$14.86	$94.27	16.55%	8.86%	7.69%
4	1980	$14.82	$102.48	15.06%	9.97%	5.09%
5	1981	$15.36	$109.43	14.50%	11.55%	2.95%
6	1982	$12.64	$112.46	11.39%	13.50%	-2.11%
7	1983	$14.03	$116.93	12.23%	10.38%	1.85%
8	1984	$16.64	$122.47	13.90%	11.74%	2.16%
9	1985	$14.61	$125.20	11.80%	11.25%	0.55%
10	1986	$14.48	$126.82	11.49%	8.98%	2.51%
11	1987	$17.50	$134.07	13.42%	7.92%	5.50%
12	1988	$23.75	$141.32	17.25%	8.97%	8.28%
13	1989	$22.87	$147.26	15.85%	8.81%	7.04%
14	1990	$21.73	$153.01	14.47%	8.19%	6.28%
15	1991	$16.29	$158.85	10.45%	8.22%	2.23%
16	1992	$18.86	$149.74	12.22%	7.26%	4.96%
17	1993	$21.89	$180.88	13.24%	7.17%	6.07%
18	1994	$30.60	$193.06	16.37%	6.59%	9.78%
19	1995	$33.96	$216.51	16.58%	7.60%	8.98%
20	1996	$38.73	$237.08	17.08%	6.18%	10.90%
21	1997	$39.72	$249.52	16.33%	6.64%	9.69%
22	1998	$37.71	$266.40	14.62%	5.83%	8.79%
23	1999	$48.17	$290.68	17.29%	5.57%	11.72%
24	2000	$50.00	$325.80	16.22%	6.50%	9.72%
25	2001	$24.70	$338.37	7.44%	5.53%	1.91%
26	2002	$27.59	$321.72	8.36%	5.59%	2.77%
27	2003	$48.73	$367.17	14.15%	4.80%	9.35%
28	2004	$58.55	$414.75	14.98%	5.02%	9.96%
29	2005	$69.93	$453.06	16.12%	4.69%	11.43%
30	2006	$81.51	$504.39	17.03%	4.68%	12.35%
31	2007	$66.18	$529.59	12.80%	4.86%	7.94%
32	2008	$14.88	$451.37	3.03%	4.45%	-1.42%
33	2009	$50.97	$513.58	10.56%	3.47%	7.09%
34	2010	$77.35	$579.14	14.16%	4.25%	9.91%
35	2011	$86.95	$613.14	14.59%	3.82%	10.77%
36	2012	$86.51	$666.97	13.52%	2.46%	11.06%
37	2013	$100.20	$715.84	14.49%	2.88%	11.61%
38	2014	$102.31	$726.96	14.18%	3.41%	10.77%
39	2015	$86.53	$740.29	11.79%	2.55%	9.24%
40	2016	$94.55	$768.98	12.53%	2.30%	10.23%
41	2017	$109.88	$807.04	13.94%	2.65%	11.29%
42	2018	$132.39	$841.26	16.06%	3.11%	12.95%
43	2019	$139.47	$892.65	16.09%	2.40%	13.69%
44	2020	$94.13	$908.86	10.45%	1.42%	9.03%
45	2021	$197.87	$974.83	21.01%	2.14%	18.87%
	Average			**13.88%**	**6.18%**	**7.69%**

[A]: Diluted earnings per share on the S&P 500 Composite Index.
[B]: Book value per share on the S&P 500 Composite Index.
[C]: Average of current- and prior year [B] / current year [A].
[D]: Annual income returns on 20-year U.S. Treasury bonds.
[E]: [C] - [D]
Sources for [A] and [B]:
Standard & Poor's 500 Earnings and Book Value Per Share:
https://ycharts.com/indicators/reports/sp_500_earnings
https://ycharts.com/indicators/sandp_500_book_value_per_share
Source for [D]: Morningstar 2015 Classic Yearbook (Table A-7) and
U.S. Department of the Treasury
https://www.treasury.gov/Pages/default.aspx

Market Risk Premium used in RUCO's CAPM Analysis
Based on the Differential of Arithmetic and Geometric Total Returns on Large Cap Stocks and
Long-Term Government Bonds, measured over the period 1926-2021,
and actual Annual Returns on Equity of the S&P 500 compared to actual Annual Income Returns
on 20-Yr U.S. Treasury Bonds, 1978-2020

Line No.	Long-Term Government Bonds, as measured over the period 1926-2021	[A] S&P 500	[B] L-T Gov't Bonds	[C] Risk Premium 1-Factor	[D] Risk Premium 2-Factor	[E] Risk Premium 3-Factor
1	Arithmetic Mean	12.3%	6.0%	6.3%	6.3%	6.3%
2	Geometric Mean	10.5%	5.5%	5.0%	5.0%	5.0%
3	Average - Arithmetic & Geometric Mean			**5.65%**	5.65%	
4	Risk Premium - Schedule JAC-4 (Page 2 of 4)				7.69%	7.69%
5	Average -- 2 Risk Premia				**6.67%**	
6	Simple Average -- 3 Risk Premia					**6.33%**

Reference:
Column [A]: Arithmetic and Geometric Total Returns on Large-Cap Stocks, 1926-2021 (Source: KROLL 2022 SBBI Yearbook, p. 58)
Column [B]: Arithmetic and Geometric Total Returns on Long-Term Government Bonds, 1926-2022 (Source: KROLL 2022 SBBI Yearbook, p. 58)
Line 1: [A] - [B] = [C]
Line 2: [A] - [B] = [C]
Line 3: ([C] Line 1 - [C] Line 2)/2
Line 4: Schedule JAC-4 (Page 2 of 2), Line 45
Line 5: ([C] Line 3 + [D] Line 4)/2
Line 6: ([D] Line 1 + [D] Line 2 + [D] Line 4)/3

Hamada Risk Adjustment
Applied to Tucson Electric Power
Based on Debt and Equity Ratios of RUCO's Proxy Companies
as Reported by Value Line

(Equity Risk Premium of 6.33%; R_F rate based on average 20- and 30-Year Treasury Yield)

Unlevering Beta

Proxy Debt Ratio	52.89%	[1]
Proxy Equity Ratio	47.11%	[2]
Debt / Equity Ratio	112.25%	[3]
Tax Rate	24.91%	[4]
Equity Risk Premium	6.33%	[5]
Risk-free Rate	3.98%	[6]
Proxy Group Beta	0.87	[7]
Unlevered Beta	0.47	[8]

Relevered Betas and Cost of Equity Estimates

[9] Debt Ratio	[10] D / E Ratio	[11] Levered Beta	[12] Cost of Equity
0%	0.00%	0.474	6.99%
20%	25.00%	0.563	7.55%
30%	42.86%	0.626	7.95%
40%	66.67%	0.711	8.49%
45.68%	84.09%	0.773	**8.88%**
50%	100.00%	0.830	9.24%
52.89%	112.25%	0.873	**9.51%**
55%	122.22%	0.909	9.74%
60%	150.00%	1.008	10.36%

[1] Proxy Debt Ratio
[2] Proxy Equity Ratio
[3] = [1] / [2]
[4] Tax Rate (as provided by RUCO Witness Michlik -- 21.00% Federal tax + 3.9113% AZ tax)
[5] Equity Risk Premium from Schedule JAC-4 (Page 3 of 3)
[6] Risk Free Rate from Schedule JAC-4 (Page 1 of 3)
[7] Average Proxy Group Beta from Schedule JAC-4 (Page 1 of 3)
[8] = [7] / (1 + (1 - [4]) * [3])
[9] Various debt ratios for modeling
[10] = [9] / (1 - [9])
[11] = [8] * (1 + (1 - [4]) * [10])
[12] = [6] + [11] * [5]

ECONOMIC INDICATORS

Line No	Year	Real GDP Growth	Industrial Production Growth	Unemployment Rate	Consumer Price Index	Producer Price Index
			1975 - 1982 Cycle			
1	1975	-1.1%	-8.9%	8.5%	7.0%	6.6%
2	1976	5.4%	10.8%	7.7%	4.8%	3.7%
3	1977	5.5%	5.9%	7.0%	6.8%	6.9%
4	1978	5.0%	5.7%	6.0%	9.0%	9.2%
5	1979	2.8%	4.4%	5.8%	13.3%	12.8%
6	1980	-0.2%	-1.9%	7.0%	12.4%	11.8%
7	1981	1.8%	1.9%	7.5%	8.9%	7.1%
8	1982	-2.1%	-4.4%	9.5%	3.8%	3.6%
			1983 - 1991 Cycle			
9	1983	4.0%	3.7%	9.5%	3.8%	0.6%
10	1984	6.8%	9.3%	7.5%	3.9%	1.7%
11	1985	3.7%	1.7%	7.2%	3.8%	1.8%
12	1986	3.1%	0.9%	7.0%	1.1%	-2.3%
13	1987	2.9%	4.9%	6.2%	4.4%	2.2%
14	1988	3.8%	4.5%	5.5%	4.4%	4.0%
15	1989	3.5%	1.8%	5.3%	4.6%	4.9%
16	1990	1.8%	-0.2%	5.6%	6.1%	5.7%
17	1991	-0.5%	-2.0%	6.8%	3.1%	-0.1%
			1992 - 2001 Cycle			
18	1992	3.0%	3.1%	7.5%	2.9%	1.6%
19	1993	2.7%	3.4%	6.9%	2.7%	0.2%
20	1994	4.0%	5.5%	6.1%	2.7%	1.7%
21	1995	3.7%	4.8%	5.6%	2.5%	2.3%
22	1996	4.5%	4.3%	5.4%	3.3%	2.8%
23	1997	4.5%	7.3%	4.9%	1.7%	-1.2%
24	1998	4.2%	5.8%	4.5%	1.6%	0.0%
25	1999	3.7%	4.5%	4.2%	2.7%	2.9%
26	2000	4.1%	4.0%	4.0%	3.4%	3.6%
27	2001	1.1%	-3.4%	4.7%	1.6%	-1.6%
			2002 - 2009 Cycle			
28	2002	1.8%	0.2%	5.8%	2.4%	1.2%
29	2003	2.8%	1.2%	6.0%	1.9%	4.0%
30	2004	3.8%	2.3%	5.5%	3.3%	4.2%
31	2005	3.3%	3.2%	5.1%	3.4%	5.4%
32	2006	2.7%	2.2%	4.6%	2.5%	1.1%
33	2007	1.8%	2.5%	4.6%	4.1%	6.2%
34	2008	-0.1%	-3.5%	5.8%	0.1%	-0.9%
35	2009	-2.5%	-11.5%	9.3%	2.7%	4.3%
			Current Cycle			
36	2010	2.6%	5.5%	9.6%	1.5%	4.7%
37	2011	1.5%	3.1%	8.9%	3.0%	6.9%
38	2012	2.3%	3.0%	8.1%	1.7%	1.6%
39	2013	1.8%	2.0%	7.4%	1.5%	0.8%
40	2014	2.3%	3.0%	6.2%	0.8%	1.2%
41	2015	2.7%	-1.4%	5.3%	0.7%	-4.3%
42	2016	1.7%	-2.2%	4.9%	2.1%	-1.4%
43	2017	2.3%	1.3%	4.4%	2.1%	3.3%
44	2018	2.9%	3.2%	3.9%	1.9%	3.4%
45	2019	2.3%	-0.8%	3.7%	2.3%	0.4%
46	2020	-3.4%	-7.2%	8.1%	1.4%	-1.5%
47	2021	5.7%	5.6%	5.3%	7.0%	10.6%

Source: Council of Economic Advisors, Economic Indicators, various issues.
https://www.govinfo.gov/app/collection/econi/2022

Note: Annual measures of Real GDP growth, Industrial Production growth, and the Producer Price Index for year 2021 are preliminary.

ECONOMIC INDICATORS

Line No	Year	Real GDP* Growth	Industrial Production Growth	Unemploy-ment Rate	Consumer Price Index	Producer Price Index
1	2009					
2	1st Qtr.	-5.3%	-11.6%	8.1%	2.4%	-0.4%
3	2nd Qtr.	-0.3%	-12.9%	9.3%	3.2%	9.2%
4	3rd Qtr.	1.4%	-9.3%	9.6%	2.0%	-0.8%
5	4th Qtr.	4.0%	-4.5%	10.0%	2.5%	8.8%
6	2010					
7	1st Qtr.	1.6%	2.7%	9.7%	0.9%	6.5%
8	2nd Qtr.	3.9%	6.5%	9.7%	-1.2%	-2.4%
9	3rd Qtr.	2.8%	6.9%	9.6%	2.8%	4.0%
10	4th Qtr.	2.8%	6.2%	9.6%	2.8%	9.2%
11	2011					
12	1st Qtr.	-1.5%	5.4%	9.0%	4.8%	9.6%
13	2nd Qtr.	2.9%	3.6%	9.0%	3.2%	3.6%
14	3rd Qtr.	0.8%	3.3%	9.1%	2.4%	6.4%
15	4th Qtr.	4.6%	4.0%	8.7%	0.4%	-1.2%
16	2012					
17	1st Qtr.	2.3%	4.5%	8.3%	3.2%	2.0%
18	2nd Qtr.	1.6%	4.7%	8.2%	0.0%	-2.8%
19	3rd Qtr.	2.5%	3.4%	8.1%	4.0%	9.6%
20	4th Qtr.	0.1%	2.8%	7.8%	0.0%	-3.6%
21	2013					
22	1st Qtr.	1.9%	2.5%	7.7%	2.0%	1.2%
23	2nd Qtr.	1.1%	2.0%	7.6%	1.2%	2.4%
24	3rd Qtr.	3.0%	2.6%	7.3%	1.6%	0.0%
25	4th Qtr.	3.8%	3.3%	7.0%	1.2%	0.3%
26	2014					
27	1st Qtr.	-1.2%	3.2%	6.6%	1.6%	0.3%
28	2nd Qtr.	4.0%	4.2%	6.2%	3.6%	0.2%
29	3rd Qtr.	5.0%	4.7%	6.1%	0.0%	0.0%
30	4th Qtr.	2.3%	4.5%	5.7%	-2.8%	-0.8%
31	2015					
32	1st Qtr.	3.2%	3.5%	5.6%	-0.2%	-2.3%
33	2nd Qtr.	2.7%	1.5%	5.4%	0.6%	1.2%
34	3rd Qtr.	1.6%	1.1%	5.2%	0.0%	-1.8%
35	4th Qtr.	0.5%	-0.8%	5.0%	0.2%	-0.9%
36	2016					
37	1st Qtr.	1.5%	-1.7%	4.9%	1.1%	-2.7%
38	2nd Qtr.	2.3%	-1.3%	4.9%	1.0%	-2.2%
39	3rd Qtr.	1.9%	-1.2%	4.9%	1.1%	-1.5%
40	4th Qtr.	1.8%	-0.1%	4.7%	1.8%	0.9%
41	2017					
42	1st Qtr.	1.8%	0.6%	4.7%	2.5%	3.7%
43	2nd Qtr.	3.0%	2.2%	4.3%	1.9%	3.1%
44	3rd Qtr.	2.8%	1.6%	4.3%	1.9%	2.9%
45	4th Qtr.	2.3%	3.5%	4.1%	2.1%	3.6%
46	2018					
47	1st Qtr.	2.2%	3.5%	4.1%	1.7%	3.2%
48	2nd Qtr.	4.2%	3.3%	3.9%	2.3%	3.9%
49	3rd Qtr.	3.4%	4.9%	3.8%	1.3%	3.9%
50	4th Qtr.	2.2%	3.9%	3.8%	1.0%	2.5%
51	2019					
52	1st Qtr.	2.4%	2.9%	3.9%	0.2%	0.8%
53	2nd Qtr.	3.2%	1.1%	3.6%	0.2%	0.8%
54	3rd Qtr.	2.8%	0.2%	3.6%	0.2%	-0.1%
55	4th Qtr.	1.9%	-0.7%	3.5%	0.2%	0.2%
56	2020					
57	1st Qtr.	-5.1%	-1.9%	3.8%	-0.1%	0.2%
58	2nd Qtr.	-31.2%	-15.0%	13.1%	-0.1%	-3.8%
59	3rd Qtr.	33.8%	-6.7%	8.8%	0.4%	-1.6%
60	4th Qtr.	4.5%	-4.2%	6.8%	0.2%	-0.6%
61	2021					
62	1st Qtr.	6.3%	-1.6%	6.2%	0.4%	3.9%
63	2nd Qtr.	6.7%	14.2%	5.9%	0.7%	11.3%
64	3rd Qtr.	2.3%	4.9%	5.1%	0.4%	12.7%
65	4th Qtr.	6.9%	4.5%	4.2%	0.7%	14.2%
66	2022					
67	1st Qtr.	-1.6%	4.9%	3.8%	0.9%	14.6%
68	2nd Qtr.	-0.6%	4.5%	3.6%	0.9%	16.9%
69	3rd Qtr.	2.9%	4.2%	3.6%	0.2%	12.7%
70	4th Qtr.					

*GDP=Gross Domestic Product
Source: Council of Economic Advisors, Economic Indicators, various issues.

INTEREST RATES

Line No	Year	Prime Rate	US Treasury T Bills 3 Month	US Treasury T Bonds 10 Year	Utility Bonds Aaa		Utility Bonds Aa	Utility Bonds A	Utility Bonds Baa
1	1975	7.86%	5.84%	7.99%	9.03%		9.44%	10.09%	10.96%
2	1976	6.84%	4.99%	7.61%	8.63%		8.92%	9.29%	9.82%
3	1977	6.83%	5.27%	7.42%	8.19%		8.43%	8.61%	9.06%
4	1978	9.06%	7.22%	8.41%	8.87%		9.10%	9.29%	9.62%
5	1979	12.67%	10.04%	9.43%	9.86%		10.22%	10.49%	10.96%
6	1980	15.27%	11.51%	11.43%	12.30%		13.00%	13.34%	13.95%
7	1981	18.89%	14.03%	13.92%	14.64%		15.30%	15.95%	16.60%
8	1982	14.86%	10.69%	13.01%	14.22%		14.79%	15.86%	16.45%
9	1983	10.79%	8.63%	11.10%	12.52%		12.83%	13.66%	14.20%
10	1984	12.04%	9.58%	12.46%	12.72%		13.66%	14.03%	14.53%
11	1985	9.93%	7.48%	10.62%	11.68%		12.06%	12.47%	12.96%
12	1986	8.33%	5.98%	7.67%	8.92%		9.30%	9.58%	10.00%
13	1987	8.21%	5.82%	8.39%	9.52%		9.77%	10.10%	10.53%
14	1988	9.32%	6.69%	8.85%	10.05%		10.26%	10.49%	11.00%
15	1989	10.87%	8.12%	8.49%	9.32%		9.56%	9.77%	9.97%
16	1990	10.01%	7.51%	8.55%	9.45%		9.65%	9.86%	10.06%
17	1991	8.46%	5.42%	7.86%	8.85%		9.09%	9.36%	9.55%
18	1992	6.25%	3.45%	7.01%	8.19%		8.55%	8.69%	8.86%
19	1993	6.00%	3.02%	5.87%	7.29%		7.44%	7.59%	7.91%
20	1994	7.15%	4.29%	7.09%	8.07%		8.21%	8.31%	8.63%
21	1995	8.83%	5.51%	6.57%	7.68%		7.77%	7.89%	8.29%
22	1996	8.27%	5.02%	6.44%	7.48%		7.57%	7.75%	8.16%
23	1997	8.44%	5.07%	6.35%	7.43%		7.54%	7.60%	7.95%
24	1998	8.35%	4.81%	5.26%	6.77%		6.91%	7.04%	7.26%
25	1999	8.00%	4.66%	5.65%	7.21%		7.51%	7.62%	7.88%
26	2000	9.23%	5.85%	6.03%	7.88%		8.06%	8.24%	8.36%
27	2001	6.91%	3.44%	5.02%	7.47%		7.59%	7.78%	8.02%
28	2002	4.67%	1.62%	4.61%		[1]	7.19%	7.37%	8.02%
29	2003	4.12%	1.01%	4.01%			6.40%	6.58%	6.84%
30	2004	4.34%	1.38%	4.27%			6.04%	6.16%	6.40%
31	2005	6.19%	3.16%	4.29%			5.44%	5.65%	5.93%
32	2006	7.96%	4.73%	4.80%			5.84%	6.07%	6.32%
33	2007	8.05%	4.41%	4.63%			5.94%	6.07%	6.33%
34	2008	5.09%	1.48%	3.66%			6.18%	6.53%	7.25%
35	2009	3.25%	0.16%	3.26%			5.75%	6.04%	7.06%
36	2010	3.25%	0.14%	3.22%			5.24%	5.46%	5.96%
37	2011	3.25%	0.06%	2.78%			4.78%	5.04%	5.57%
38	2012	3.25%	0.09%	1.80%			3.83%	4.13%	4.86%
39	2013	3.25%	0.06%	2.35%			4.24%	4.47%	4.98%
40	2014	3.25%	0.03%	2.54%			4.19%	4.28%	4.80%
41	2015	3.27%	0.06%	2.14%			4.00%	4.12%	5.03%
42	2016	3.51%	0.33%	1.84%			3.73%	3.93%	4.68%
43	2017	4.13%	0.94%	2.33%			3.82%	4.00%	4.38%
44	2018	4.96%	1.94%	2.91%			4.09%	4.25%	4.67%
45	2019	5.25%	2.09%	2.14%			3.61%	3.77%	4.19%
46	2020	3.50%	0.37%	0.89%			2.79%	3.02%	3.39%
47	2021	3.25%	0.05%	1.44%			2.97%	3.11%	3.36%

[1] Note: Moody's has not published Aaa utility bond yields since 2001.

Sources: Council of Economic Advisors, Economic Indicators; Mergent Bond Record; Federal Reserve Bulletin; various issues.

INTEREST RATES

Line No		Prime Rate	US Treasury T Bills 3 Month	US Treasury T Bonds 10 Year	Utility Bonds Aa	Utility Bonds A	Utility Bonds Baa
1	**2011**						
2	Jan	3.25%	0.15%	3.39%	5.29%	5.57%	6.06%
3	Feb	3.25%	0.14%	3.58%	5.42%	5.68%	6.10%
4	Mar	3.25%	0.11%	3.41%	5.33%	5.56%	5.97%
5	Apr	3.25%	0.06%	3.46%	5.32%	5.55%	5.98%
6	May	3.25%	0.04%	3.17%	5.08%	5.32%	5.74%
7	June	3.25%	0.04%	3.00%	5.04%	5.26%	5.67%
8	July	3.25%	0.03%	3.00%	5.05%	5.27%	5.70%
9	Aug	3.25%	0.05%	2.30%	4.44%	4.69%	5.22%
10	Sept	3.25%	0.02%	1.98%	4.24%	4.48%	5.11%
11	Oct	3.25%	0.02%	2.15%	4.21%	4.52%	5.24%
12	Nov	3.25%	0.01%	2.01%	3.92%	4.25%	4.93%
13	Dec	3.25%	0.02%	1.98%	4.00%	4.33%	5.07%
14	**2012**						
15	Jan	3.25%	0.02%	1.97%	4.03%	4.34%	5.06%
16	Feb	3.25%	0.08%	1.97%	4.02%	4.36%	5.02%
17	Mar	3.25%	0.09%	2.17%	4.16%	4.48%	5.13%
18	Apr	3.25%	0.08%	2.05%	4.10%	4.40%	5.11%
19	May	3.25%	0.09%	1.80%	3.92%	4.20%	4.97%
20	June	3.25%	0.09%	1.62%	3.79%	4.08%	4.91%
21	July	3.25%	0.10%	1.53%	3.58%	3.93%	4.85%
22	Aug	3.25%	0.11%	1.68%	3.65%	4.00%	4.88%
23	Sept	3.25%	0.10%	1.72%	3.69%	4.02%	4.81%
24	Oct	3.25%	0.10%	1.75%	3.68%	3.91%	4.54%
25	Nov	3.25%	0.11%	1.65%	3.60%	3.84%	4.42%
26	Dec	3.25%	0.08%	1.72%	3.75%	4.00%	4.56%
27	**2013**						
28	Jan	3.25%	0.07%	1.91%	3.90%	4.15%	4.66%
29	Feb	3.25%	0.10%	1.98%	3.95%	4.18%	4.74%
30	Mar	3.25%	0.09%	1.96%	3.90%	4.15%	4.66%
31	Apr	3.25%	0.06%	1.76%	3.74%	4.00%	4.49%
32	May	3.25%	0.05%	1.93%	3.91%	4.17%	4.65%
33	June	3.25%	0.05%	2.30%	4.27%	4.53%	5.08%
34	July	3.25%	0.04%	2.58%	4.44%	4.68%	5.21%
35	Aug	3.25%	0.04%	2.74%	4.53%	4.73%	5.28%
36	Sept	3.25%	0.02%	2.81%	4.58%	4.80%	5.31%
37	Oct	3.25%	0.06%	2.62%	4.48%	4.70%	5.17%
38	Nov	3.25%	0.07%	2.72%	4.56%	4.77%	5.24%
39	Dec	3.25%	0.07%	2.90%	4.59%	4.81%	5.25%
40	**2014**						
41	Jan	3.25%	0.05%	2.86%	4.44%	4.63%	5.09%
42	Feb	3.25%	0.06%	2.71%	4.38%	4.53%	5.01%
43	Mar	3.25%	0.05%	2.72%	4.40%	4.51%	5.00%
44	Apr	3.25%	0.04%	2.71%	4.30%	4.41%	4.85%
45	May	3.25%	0.03%	2.56%	4.16%	4.26%	4.69%
46	June	3.25%	0.03%	2.60%	4.23%	4.29%	4.73%
47	July	3.25%	0.03%	2.54%	4.16%	4.23%	4.66%
48	Aug	3.25%	0.03%	2.42%	4.07%	4.13%	4.65%
49	Sept	3.25%	0.02%	2.53%	4.18%	4.24%	4.79%
50	Oct	3.25%	0.02%	2.30%	3.96%	4.06%	4.67%
51	Nov	3.25%	0.02%	2.33%	4.03%	4.09%	4.75%
52	Dec	3.25%	0.04%	2.21%	3.90%	3.95%	4.70%

Line No		Prime Rate	US Treasury T Bills 3 Month	US Treasury T Bonds 10 Year	Utility Bonds Aa	Utility Bonds A	Utility Bonds Baa
1	**2015**						
2	Jan	3.25%	0.03%	1.88%	3.52%	3.58%	4.39%
3	Feb	3.25%	0.02%	1.98%	3.62%	3.67%	4.44%
4	Mar	3.25%	0.03%	2.04%	3.67%	3.74%	4.51%
5	Apr	3.25%	0.02%	1.94%	3.63%	3.75%	4.51%
6	May	3.25%	0.02%	2.20%	4.05%	4.17%	4.91%
7	June	3.25%	0.02%	2.36%	4.29%	4.39%	5.13%
8	July	3.25%	0.03%	2.32%	4.27%	4.40%	5.22%
9	Aug	3.25%	0.07%	2.17%	4.13%	4.25%	5.23%
10	Sept	3.25%	0.02%	2.17%	4.25%	4.39%	5.42%
11	Oct	3.25%	0.02%	2.07%	4.13%	4.29%	5.47%
12	Nov	3.25%	0.13%	2.26%	4.22%	4.40%	5.57%
13	Dec	3.50%	0.23%	2.24%	4.18%	4.35%	5.55%
14	**2016**						
15	Jan	3.50%	0.26%	2.09%	4.09%	4.27%	5.49%
16	Feb	3.50%	0.31%	1.78%	3.94%	4.11%	5.28%
17	Mar	3.50%	0.30%	1.89%	3.93%	4.16%	5.12%
18	Apr	3.50%	0.23%	1.81%	3.74%	4.00%	4.75%
19	May	3.50%	0.27%	1.81%	3.65%	3.93%	4.60%
20	Jun	3.50%	0.27%	1.64%	3.56%	3.78%	4.47%
21	Jul	3.50%	0.30%	1.50%	3.36%	3.57%	4.16%
22	Aug	3.50%	0.30%	1.56%	3.39%	3.59%	4.20%
23	Sep	3.50%	0.29%	1.63%	3.47%	3.66%	4.27%
24	Oct	3.50%	0.33%	1.76%	3.59%	3.77%	4.34%
25	Nov	3.50%	0.45%	2.14%	3.91%	4.08%	4.64%
26	Dec	3.75%	0.51%	2.49%	4.11%	4.27%	4.79%
27	**2017**						
28	Jan	3.75%	0.52%	2.43%	3.96%	4.14%	4.62%
29	Feb	3.75%	0.53%	2.42%	3.99%	4.18%	4.58%
30	Mar	4.00%	0.72%	2.48%	4.04%	4.23%	4.62%
31	Apr	4.00%	0.81%	2.30%	3.93%	4.12%	4.51%
32	May	4.00%	0.89%	2.30%	3.94%	4.12%	4.50%
33	Jun	4.25%	0.99%	2.19%	3.77%	3.94%	4.32%
34	Jul	4.25%	1.08%	2.32%	3.82%	3.99%	4.36%
35	Aug	4.25%	1.03%	2.21%	3.67%	3.86%	4.23%
36	Sep	4.25%	1.04%	2.20%	3.70%	3.87%	4.24%
37	Oct	4.25%	1.08%	2.36%	3.74%	3.91%	4.26%
38	Nov	4.25%	1.25%	2.35%	3.65%	3.83%	4.16%
39	Dec	4.50%	1.34%	2.40%	3.62%	3.79%	4.14%
40	**2018**						
41	Jan	4.50%	1.43%	2.58%	3.69%	3.86%	4.18%
42	Feb	4.50%	1.59%	2.86%	3.94%	4.09%	4.42%
43	Mar	4.75%	1.73%	2.84%	3.97%	4.13%	4.52%
44	Apr	4.75%	1.79%	2.87%	3.99%	4.17%	4.58%
45	May	4.75%	1.90%	2.98%	4.10%	4.28%	4.71%
46	Jun	5.00%	1.94%	2.91%	4.11%	4.27%	4.71%
47	Jul	5.00%	1.99%	2.89%	4.10%	4.27%	4.67%
48	Aug	5.00%	2.07%	2.89%	4.08%	4.26%	4.64%
49	Sep	5.25%	2.17%	3.00%	4.18%	4.32%	4.74%
50	Oct	5.25%	2.29%	3.15%	4.31%	4.45%	4.91%
51	Nov	5.25%	2.37%	3.12%	4.40%	4.52%	5.03%
52	Dec	5.50%	2.41%	2.83%	4.24%	4.37%	4.92%

Line No		Prime Rate	US Treasury T Bills 3 Month	US Treasury T Bonds 10 Year	Utility Bonds Aa	Utility Bonds A	Utility Bonds Baa
1	**2019**						
2	Jan	5.50%	2.42%	2.71%	4.18%	4.35%	4.91%
3	Feb	5.50%	2.44%	2.68%	4.05%	4.25%	4.76%
4	Mar	5.50%	2.45%	2.57%	3.98%	4.16%	4.65%
5	Apr	5.50%	2.43%	2.53%	3.91%	4.08%	4.55%
6	May	5.50%	2.40%	2.40%	3.84%	3.98%	4.47%
7	Jun	5.50%	2.22%	2.07%	3.65%	3.82%	4.31%
8	Jul	5.50%	2.15%	2.06%	3.53%	3.69%	4.13%
9	Aug	5.25%	1.99%	1.63%	3.17%	3.29%	3.63%
10	Sep	5.00%	1.93%	1.70%	3.24%	3.37%	3.71%
11	Oct	4.75%	1.55%	1.71%	3.24%	3.39%	3.72%
12	Nov	4.75%	1.54%	1.81%	3.25%	3.43%	3.76%
13	Dec	4.75%	1.57%	1.86%	3.22%	3.40%	3.73%
14	**2020**						
15	Jan	4.75%	1.55%	1.76%	3.12%	3.29%	3.60%
16	Feb	4.75%	1.54%	1.50%	2.96%	3.11%	3.42%
17	Mar	3.25%	0.30%	0.87%	3.30%	3.50%	3.96%
18	Apr	3.25%	0.14%	0.66%	2.93%	3.19%	3.82%
19	May	3.25%	0.13%	0.67%	2.89%	3.14%	3.63%
20	Jun	3.25%	0.16%	0.73%	2.80%	3.07%	3.44%
21	Jul	3.25%	0.13%	0.62%	2.46%	2.74%	3.09%
22	Aug	3.25%	0.10%	0.65%	2.49%	2.73%	3.06%
23	Sep	3.25%	0.11%	0.68%	2.62%	2.84%	3.17%
24	Oct	3.25%	0.10%	0.79%	2.72%	2.95%	3.27%
25	Nov	3.25%	0.09%	0.87%	2.63%	2.85%	3.17%
26	Dec	3.25%	0.09%	0.93%	2.57%	2.77%	3.05%
27	**2021**						
28	Jan	3.25%	0.08%	1.08%	2.73%	2.91%	3.18%
29	Feb	3.25%	0.04%	1.26%	2.93%	3.09%	3.37%
30	Mar	3.25%	0.03%	1.61%	3.27%	3.44%	3.72%
31	Apr	3.25%	0.021%	1.64%	3.13%	3.30%	3.57%
32	May	3.25%	0.018%	1.62%	3.17%	3.33%	3.58%
33	Jun	3.25%	0.036%	1.52%	3.01%	3.16%	3.41%
34	Jul	3.25%	0.052%	1.32%	2.80%	2.95%	3.20%
35	Aug	3.25%	0.055%	1.28%	2.82%	2.95%	3.19%
36	Sep	3.25%	0.042%	1.37%	2.84%	2.96%	3.19%
37	Oct	3.25%	0.052%	1.58%	2.99%	3.09%	3.32%
38	Nov	3.25%	0.052%	1.56%	2.91%	3.02%	3.25%
39	Dec	3.25%	0.059%	1.47%	3.01%	3.13%	3.36%
40	**2022**						
41	Jan	3.25%	0.14%	1.76%	3.19%	3.33%	3.57%
42	Feb	3.25%	0.31%	1.93%	3.56%	3.68%	3.95%
43	Mar	3.50%	0.45%	2.13%	3.81%	3.98%	4.28%
44	Apr	3.50%	0.76%	2.75%	4.10%	4.32%	4.61%
45	May	4.00%	0.99%	2.90%	4.55%	4.75%	5.07%
46	Jun	4.75%	1.54%	3.14%	4.65%	4.86%	5.22%
47	Jul	5.50%	2.30%	2.90%	4.57%	4.78%	5.15%
48	Aug	5.50%	2.72%	2.90%	4.54%	4.76%	5.09%
49	Sep	6.25%	3.22%	3.52%	5.08%	5.28%	5.61%
50	Oct	6.25%	3.87%	3.98%	5.68%	5.88%	6.18%
51	Nov	7.00%	4.32%	3.89%	5.54%	5.75%	6.05%
52	Dec	7.50%	4.36%	3.62%	5.06%	5.28%	5.57%

[1] Note: Moody's has not published Aaa utility bond yields since 2001.
Sources: Council of Economic Advisors, Economic Indicators; Mergent Bond Record; Federal Reserve Bulletin; various issues.

STOCK PRICE INDICATORS

Line No	Year	S&P Composite	NASDAQ Composite	DJIA	S&P Dividend/Price Ratio	S&P Earnings/Price Ratio
1	1975			802.49	4.31%	9.15%
2	1976			974.92	3.77%	8.90%
3	1977			894.63	4.62%	10.79%
4	1978			820.23	5.28%	12.03%
5	1979			844.40	5.47%	13.46%
6	1980			891.41	5.26%	12.66%
7	1981			932.92	5.20%	11.96%
8	1982			884.36	5.81%	11.60%
9	1983			1,190.34	4.40%	8.03%
10	1984			1,178.48	4.64%	10.02%
11	1985			1,328.23	4.25%	8.12%
12	1986			1,792.76	3.49%	6.09%
13	1987			2,275.99	3.08%	5.48%
14	1988			2,060.82	3.64%	8.01%
15	1989	322.84		2,508.91	3.45%	7.41%
16	1990	334.59		2,678.94	3.61%	6.47%
17	1991	376.18	491.69	2,929.33	3.24%	4.79%
18	1992	415.74	599.26	3,284.29	2.99%	4.22%
19	1993	451.21	715.16	3,522.06	2.78%	4.46%
20	1994	460.42	751.65	3,793.77	2.82%	5.83%
21	1995	541.72	925.19	4,493.76	2.56%	6.09%
22	1996	670.50	1,164.96	5,742.89	2.19%	5.24%
23	1997	873.43	1,469.49	7,441.15	1.77%	4.57%
24	1998	1,085.50	1,794.91	8,625.52	1.49%	3.46%
25	1999	1,327.33	2,728.15	10,464.88	1.25%	3.17%
26	2000	1,427.22	2,783.67	10,734.90	1.15%	3.63%
27	2001	1,194.18	2,035.00	10,189.13	1.32%	2.95%
28	2002	993.94	1,539.73	9,226.43	1.61%	2.92%
29	2003	965.23	1,647.17	8,993.59	1.77%	3.84%
30	2004	1,130.65	1,986.53	10,317.39	1.72%	4.89%
31	2005	1,207.06	2,099.03	10,547.67	1.83%	5.36%
32	2006	1,310.67	2,265.17	11,408.67	1.87%	5.78%
33	2007	1,476.66	2,577.12	13,169.98	1.86%	5.29%
34	2008	1,220.89	2,162.46	11,252.61	2.37%	3.54%
35	2009	946.73	1,841.03	8,876.15	2.40%	1.86%
36	2010	1,139.31	2,347.70	10,662.80	1.97%	6.04%
37	2011	1,268.89	2,680.42	11,966.36	1.99%	6.77%
38	2012	1,379.56	2,965.77	12,967.08	2.09%	6.20%
39	2013	1,642.51	3,537.69	14,999.67	2.08%	5.57%
40	2014	1,930.67	4,374.31	16,773.99	1.94%	5.25%
41	2015	2,061.20	4,943.49	17,590.61	2.05%	4.59%
42	2016	2,092.39	4,982.49	17,908.08	2.18%	4.17%
43	2017	2,448.22	6,231.28	21,741.91	1.97%	4.22%
44	2018	2,744.68	7,419.27	25,045.75	1.90%	4.66%
45	2019	2,912.50	7,936.85	26,378.41	1.93%	4.53%
46	2020	3,218.50	10,192.67	26,906.89	1.89%	3.28%
47	2021	4,266.80	14,358.18	34,009.89	1.93%	3.79%

Source: Council of Economic Advisors, Economic Indicators, various issues.
https://www.gpo.gov/fdsys/browse/collection.actic

STOCK PRICE INDICATORS

Line No		S&P Composite	NASDAQ Composite	DJIA	S&P Dividends/Price Ratio	S&P Earnings/Price Ratio
1	**2009**					
2	1st Qtr.	809.31	1,485.14	7,774.06	3.00%	0.86%
3	2nd Qtr.	892.23	1,731.41	8,327.83	2.45%	0.82%
4	3rd Qtr.	996.68	1,985.25	9,229.93	2.16%	1.19%
5	4th Qtr.	1,088.70	2,162.33	10,172.78	1.99%	4.57%
6	**2010**					
7	1st Qtr.	1,121.60	2,274.88	10,454.42	1.94%	5.21%
8	2nd Qtr.	1,135.25	2,343.40	10,570.54	1.97%	6.51%
9	3rd Qtr.	1,096.39	2,237.97	10,390.24	2.09%	6.30%
10	4th Qtr.	1,204.00	2,534.62	11,236.02	1.95%	6.15%
11	**2011**					
12	1st Qtr.	1,302.74	2,741.01	12,024.62	1.85%	6.13%
13	2nd Qtr.	1,319.04	2,766.64	12,370.73	1.97%	6.35%
14	3rd Qtr.	1,237.12	2,613.11	11,671.47	2.15%	7.69%
15	4th Qtr.	1,225.65	2,600.91	11,798.65	2.25%	6.91%
16	**2012**					
17	1st Qtr.	1,347.44	2,902.90	12,839.80	2.12%	6.29%
18	2nd Qtr.	1,350.39	2,928.62	12,765.58	2.30%	6.45%
19	3rd Qtr.	1,402.21	3,029.86	13,118.72	2.27%	6.00%
20	4th Qtr.	1,418.21	3,001.69	13,142.91	2.28%	6.07%
21	**2013**					
22	1st Qtr.	1,514.41	3,177.10	14,000.30	2.21%	5.59%
23	2nd Qtr.	1,609.77	3,369.49	14,961.28	2.15%	5.66%
24	3rd Qtr.	1,675.31	3,643.63	15,255.25	2.14%	5.65%
25	4th Qtr.	1,770.45	3,960.54	15,751.96	2.06%	5.42%
26	**2014**					
27	1st Qtr.	1,834.30	4,210.05	16,170.26	2.04%	5.39%
28	2nd Qtr.	1,900.37	4,195.81	16,603.50	2.06%	5.26%
29	3rd Qtr.	1,975.95	4,483.51	16,953.85	2.02%	5.38%
30	4th Qtr.	2012.04	4607.88	17368.36	2.03%	4.97%
31	**2015**					
32	1st Qtr.	2063.46	4821.99	17806.47	2.02%	4.80%
33	2nd Qtr.	2102.03	5017.47	18007.48	2.05%	4.60%
34	3rd Qtr.	2,026.14	4,921.81	17,065.52	2.16%	4.72%
35	4th Qtr.	2,053.17	5,000.70	17,482.97	2.16%	4.23%
36	**2016**					
37	1st Qtr.	1,948.32	4,609.47	16,635.76	2.31%	4.20%
38	2nd Qtr.	2,074.99	4,845.55	17,763.85	2.19%	4.14%
39	3rd Qtr.	2,161.36	5,165.06	18,367.92	2.13%	4.11%
40	4th Qtr.	2,184.88	5,309.89	18,864.77	2.13%	4.22%
41	**2017**					
42	1st Qtr.	2,323.95	5,730.36	20,385.12	2.05%	4.24%
43	2nd Qtr.	2,396.22	6,087.11	20,979.77	2.02%	4.29%
44	3rd Qtr.	2,467.72	6,344.72	21,889.58		4.25%
45	4th Qtr.	2,604.98	6,762.93	23,713.18		4.11%
46	**2018**					
47	1st Qtr.	2,732.58	7,250.93	25,122.58	1.88%	4.37%
48	2nd Qtr.	2,703.16	7,356.20	24,555.62	1.92%	4.51%
49	3rd Qtr.	2,850.99	7,877.47	25,613.63	1.83%	4.47%
50	4th Qtr.	2,692.00	7,192.48	24,891.19	1.98%	5.28%
51	**2019**					
52	1st Qtr.	2,722.08	7,346.37	25,161.98	2.00%	4.74%
53	2nd Qtr.	2,882.89	7,874.48	26,102.16	1.93%	4.60%
54	3rd Qtr.	2,958.59	8,068.08	26,682.54	1.92%	4.46%
55	4th Qtr.	3,086.44	8,458.48	27,566.95	1.88%	4.32%
56	**2020**					
57	1st Qtr.	3,069.30	8,808.14	26,679.05	1.80%	4.50%
58	2nd Qtr.	2,928.75	9,079.35	24,542.40	2.08%	3.20%
59	3rd Qtr.	3,321.62	10,933.61	27,313.53	1.82%	2.92%
60	4th Qtr.	3,554.33	11,949.58	29,092.58		2.51%
61	**2021**					
62	1st Qtr.	3,862.56	13,364.27	31,492.85		
63	2nd Qtr.	4,182.51	13,839.28	34,121.17		
64	3rd Qtr.	4,421.15	14,839.71	34,910.40		
65	4th Qtr.	4,600.96	15,389.46	35,515.14		
66	**2022**					
67	1st Qtr.	4,467.02	14,017.79	34,711.46	1.36%	4.37%
68	2nd Qtr.	4,110.20	12,214.27	32,713.72		
69	3rd Qtr.	3,973.60	11,865.25	31,731.48		
70	4th Qtr.					

Source: Council of Economic Advisors, Economic Indicators, various issues.
https://www.gpo.gov/fdsys/browse/collection.action?collectionCode=ECONI
https://ycharts.com/indicators/sp_500_dividend_yield

PROXY GROUP COMMON EQUITY RATIOS

	Company		Historical 2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	10-Year Average 2012-2021	5-Year Average 2017-2021	Projected 2022	2023	2025-'27	5-Year Average 2022-2026	Combined 5-Yr Historical & Projected Avg.
1	ALLETE, Inc.	ALE	56.3%	55.4%	55.8%	53.7%	58.0%	59.0%	60.1%	61.4%	59.0%	57.8%	57.7%	59.5%	60.5%	60.5%	59.5%	60.2%	59.8%
2	Alliant Energy Corp.	LNT	48.4%	50.8%	47.5%	50.0%	46.1%	49.8%	45.7%	47.6%	44.9%	47.1%	47.8%	47.0%	45.5%	46.0%	45.0%	45.5%	46.3%
3	Ameren Corporation	AEE	49.4%	53.7%	51.7%	49.7%	51.3%	49.8%	48.8%	47.1%	44.3%	43.3%	48.9%	46.7%	44.0%	46.0%	48.5%	46.2%	46.4%
4	American Electric Power	AEP	49.4%	48.9%	51.0%	50.2%	50.0%	48.5%	46.8%	43.9%	41.5%	41.7%	47.2%	44.5%	42.0%	42.0%	42.5%	42.2%	43.3%
5	Duke Energy Corp.	DUK	52.9%	52.0%	52.3%	51.4%	47.4%	46.0%	46.2%	44.1%	44.4%	43.1%	48.0%	44.8%	42.0%	40.0%	37.5%	39.8%	42.3%
6	Entergy Corp.	ETR	42.9%	43.6%	43.8%	40.8%	35.5%	35.5%	35.9%	37.1%	33.7%	31.7%	38.1%	34.8%	32.5%	33.0%	33.5%	33.0%	33.9%
7	Evergy, Inc.	EVRG	N/A	N/A	N/A	N/A	N/A	N/A	60.0%	49.4%	48.7%	49.9%	52.0%	52.0%	48.5%	48.5%	46.5%	47.8%	49.9%
8	IDACORP, Inc.	IDA	54.5%	53.4%	54.7%	54.4%	55.2%	56.3%	56.4%	58.7%	56.1%	57.2%	55.7%	56.9%	56.5%	52.5%	50.0%	53.0%	55.0%
9	NextEra Energy, Inc.	NEE	40.9%	42.9%	45.0%	45.8%	46.7%	47.3%	56.0%	49.6%	46.5%	42.2%	46.3%	48.3%	41.5%	43.5%	44.0%	43.0%	45.7%
10	NorthWestern Corporation	NWE	46.2%	46.5%	46.6%	46.9%	48.0%	49.8%	47.8%	47.5%	47.2%	47.8%	47.4%	48.0%	50.0%	50.5%	51.0%	50.5%	49.3%
11	OGE Energy Corp.	OGE	49.3%	56.9%	54.1%	55.7%	58.9%	58.3%	58.0%	56.4%	51.0%	47.4%	54.6%	54.2%	53.0%	48.0%	50.0%	50.3%	52.3%
12	Otter Tail Corporation	OTTR	54.4%	57.9%	53.5%	57.6%	57.0%	58.7%	55.3%	53.1%	58.2%	57.4%	56.3%	56.5%	58.5%	58.5%	57.5%	58.2%	57.4%
13	Portland General Electric Co.	POR	52.9%	48.7%	47.3%	52.2%	51.6%	49.9%	53.5%	48.7%	46.4%	43.2%	49.4%	48.3%	44.5%	44.0%	42.5%	43.7%	46.0%
14	Southern Company	SO	47.3%	45.8%	47.3%	44.0%	35.7%	35.0%	37.6%	39.5%	38.1%	35.6%	40.6%	37.2%	36.0%	36.0%	37.0%	36.3%	36.7%
15	Xcel Energy, Inc.	XEL	46.7%	46.7%	47.0%	45.9%	43.7%	44.1%	43.6%	43.2%	42.6%	41.8%	44.5%	43.1%	42.0%	42.0%	42.0%	42.0%	42.5%
	Average		49.4%	50.2%	49.8%	49.9%	48.9%	49.1%	50.1%	48.5%	46.8%	45.8%	49.0%	48.1%	46.5%	46.1%	45.8%	46.1%	**47.11%**

Source: Value Line Investment Survey (assorted dates: October 21, 2022; November 11, 2022; and December 9, 2022).

NOTE: TEP has reduced exposure to financial risk than Ms. Bulkley's Proxy Group; thus, a downward Hamada risk adjustment should be made to TEP's COE.	
TEP Proposed Common Equity Ratio:	**54.3225%**
Ms. Bulkley's proxy group average common equity ratio:	**47.1142%**